Memorandum

Florida Department of Environmental Protection

Kim

TO: Howard L. Rhodes

THRU: Clair Fancy *CHF 10/20*
Al Linero *AAL 10/20*

FROM: Willard Hanks *WMH*

DATE: October 20, 1997

SUBJECT: Osceola Power L.P.
Modification of Permit
AIRS No. 0990331-006-AC (PSD-FL-197E)

Attached for your approval is a letter that will modify the construction permit for Osceola Power's cogeneration facilities located near Pahokee in Palm Beach County. No comments were submitted in response to the public notice for the proposed modification.

The modification will require a minor reduction in the amount of coal that can be burned in the facility, and allows increases in the hourly emissions of nitrogen oxides, sulfur dioxide, lead, mercury and carbon monoxide. Except for nitrogen oxides and lead, and as provided for by Specific Conditions of the existing permit, the proposed adjustments will result in annual emissions below the current annual permitted values. The modification also clarifies some compliance testing procedures, including when the sulfuric acid mist compliance test is to be conducted.

That part of this request having to do with the burning of tire derived fuel is being held in abeyance until after the Department reviews the test burn results. The Department may receive a similar request from this facility once emission data is collected on the burning of bagasse and tire derived fuels at this plant.

I recommend your approval and signature of the letter modifying the permit for the burning of wood waste.

WH/t

Attachment

Note: We did a BACT determination for NOx. Their previous limit which they had proposed was unrealistically low and resulted in high opacity due to ammonia salts. The BACT limit is equal to the one we set for Wheelabrator/Auburndale.
Al

FINAL DETERMINATION

Osceola Power L.P.

Modification of Permit No. AC50-269980 (PSD-FL-197B)
Permit No. 0990331-006-AC

An Intent to Issue an air construction permit modification for Osceola Power L.P., 74 Megawatt Cogeneration Facility located at U. S. Highway 98 and Hatton Highway near Pahokee, Palm Beach County, Florida was distributed on September 9, 1997. The Public Notice of Intent to Issue Air Construction Permit Modification was published in the Palm Beach Post on September 12, 1997. Copies of the modification were available for public inspection at the Department offices in Tallahassee and Fort Myers and the Palm Beach County Public Health Unit in West Palm Beach.

Comments were not submitted in response to the public notice. The final action of the Department will be to issue the permit modification as proposed.

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

October 20, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Carlos Rionda, General Manager
Osceola Power Limited Partnership
Post Office Box 606
Pahokee, Florida 33476

Re: Permit Modification No. 0990331-006-AC (PSD-FL-197C)
74 Megawatt Cogeneration Facility

Dear Mr. Rionda:

The Department has reviewed your application dated August 6, 1997 to modify the original construction permit for the Osceola Cogeneration Facility. The application is to revise emission limits for carbon monoxide (CO), lead (Pb), mercury (Hg), sulfur dioxide (SO_2), and nitrogen oxides (NO_X). An evaluation for the Prevention of Significant Deterioration (PSD) was performed and a Best Available Control Technology determination was conducted for NO_X. Construction permit No. AC50-269980 (PSD-FL-197B) is hereby modified as follows:

SPECIFIC CONDITION NO. 15.

The combined use of coal and oil shall be less than 25 percent of the total heat input to ~~this cogeneration facility~~ <u>each boiler</u> on a calendar quarter basis. The consumption of low sulfur coal shall not exceed ~~5.4 percent of the total heat input to each boiler unit in any calendar quarter. The plant shall not burn more than 18,221~~ <u>14,883</u> tons ~~of coal~~ during any 12-month period (12-month rolling average).

SPECIFIC CONDITION NO. 16.

The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, beryllium content (coal only), sulfur content, and equivalent SO_2 emission rate (in lb/MMBtu) of each fuel oil and coal delivery shall be kept in a log for at least two years. For each calendar month, the calculated SO_2, <u>mercury, and lead</u> emissions and 12-month rolling average shall be determined (in tons) and kept in a log.

SPECIFIC CONDITION NO. 19.

Visible emissions from any cogeneration boiler shall not exceed 20 percent opacity, 6-minute average, except up to 27 percent opacity is allowed for up to 6 minutes in any 1 hour period. Based on a maximum heat input to each boiler of 760 MMBtu/hr for biomass fuels, 600 MMBtu/hr for No. 2 fuel oil, and 530 MMBtu/hr for coal, stack emissions shall not exceed any limit shown in the following table:

	EMISSION LIMIT (per boiler) [d]						Total [e]
	Biomass		No. 2 Oil		Bit. Coal		Two Boilers
Pollutant	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(TPY)
Particulate (TSP)	0.03	22.8	0.03	18.0	0.03	15.9	123.1
Particulate (PM_{10})	0.03	22.8	0.03	18.0	0.03	15.9	123.1
Sulfur Dioxide							
3-hour average	---	---	---	---	1.2	636.0	---
24-hour average	0.10	76.0	0.05	30.0	1.2	636.0	---
Annual average	~~0.02 a~~				1.2 a	---	339.0 f
(Bagasse)	0.02 a b	---	---	---			
(Woodwaste)	0.05 a c						
Nitrogen Oxides							
Annual average	~~0.12~~ 0.14	~~88.2~~ 103 a	~~0.12~~ 0.14 a	~~72.0~~ 84.0 a	0.15 a	79.5 a	~~477.1~~ 577
Carbon Monoxide							
~~8~~ 24-hr average	0.35	266.0	~~0.2~~ 0.35	~~120~~ 210.0	~~0.2~~ 0.35	~~106.0~~ 185.5	1,436.4
Volatile Organic Compounds	0.06 b 0.04 c	45.6 b 30.4 c	0.03	18.0	0.03	15.9	219.2
Lead	~~2.7 x 10 -6 b~~	~~0.002~~	8.9 x 10 -7	0.0005	5.1 x 10 -6	0.0027	~~0.011~~ 0.27 f
(Bagasse)	2.7 x 10 -6 b	0.002					
(Wood Waste)	1.6 x 10 -4 c	0.12					
Mercury	~~5.7 x 10 -6 b~~ 3.5 x 10 -6 b ~~0.29 x 10 -6c~~ 4.0 x 10 -6 c	~~0.0043 b~~ 0.0027 b 0.00022 c 0.0030 c	2.4 x 10 -6	0.0014	8.4 x 10 -6	0.0045	0.0168 f
Beryllium	---	---	3.5 x 10 -7	0.0002	5.9 x 10 -6	0.0031	0.0013
Fluorides	---	---	6.3 x 10 -6	0.004	0.024	12.7	5.25
Sulfuric Acid Mist	0.005	3.72	0.0025	1.5	0.010	5.3	6.0

a Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.

b Emission limit for bagasse. Subject to revision after testing pursuant to Specific Conditions Nos. 23 and 24.

c Emission limit for woodwaste. Subject to revision after testing pursuant to Specific Conditions Nos. 23 and 24.

d The emission limit shall be prorated when more than one type of fuel is burned in a boiler.

e Limit heat input from No. 2 fuel to less than 25% of total heat input on a calendar quarter basis and coal to ~~18,221~~ 14,883 tons during any 12-month period. Combined heat input of coal and oil shall be less than 25% of the total heat input on a calendar quarter basis.

f Compliance based on a 12-month rolling average.

The permittee shall comply with the excess emissions rule contained in Rule 62-296.210, F.A.C. In addition, the permittee is allowed excess emissions during startup conditions, provided such excess emissions do not exceed a duration of four hours, and such emissions in excess of two hours do not exceed six (6) times per year.

SPECIFIC CONDITION NO. 21 STACK TESTING.

a. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct emission compliance tests for all air pollutants listed in Specific Condition No. 19 (including visible emissions). Tests shall be conducted during normal operations (i.e., within 10 percent of the permitted heat input). The permittee shall furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The emission compliance tests will be conducted in accordance with the provisions of 40 CFR 60.46a.

b. Compliance with emission limitations for each fuel stated in Specific Condition No. 20 above shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), continuous emissions monitoring data, or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), or any other method as approved by the Department, in accordance with F.A.C. Rule 17-297.620. A test protocol shall be submitted for approval to the Bureau of Air Regulation at least 90 days prior to testing.

EPA Method*	For Determination of
1	Selection of sample site and velocity traverses.
2	Stack gas flow rate when converting concentrations to or from mass emission limits.
3 or 3A	Gas analysis when needed for calculation of molecular weight or percent O_2.
4	Moisture content when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits.
5	Particulate matter concentration and mass emissions.
201 or 201A	PM_{10} emissions.
6, 6C, or 19	Sulfur dioxide emissions from stationary sources.
7 or 7E	Nitrogen oxide emissions from stationary sources.
8 (modified)	Sulfuric acid mist. **
9	Visible emission determination of opacity. - At least three one hour runs to be conducted simultaneously with particulate testing. - At least one truck unloading into the mercury reactant storage silo (from start to finish).
10	Carbon monoxide emissions from stationary sources.
12	Determination of inorganic lead emissions from stationary sources.
13A or 13B	Fluoride emissions from stationary sources.
18 or 25	Volatile organic compounds concentration.
101A	Determination of particulate and gaseous mercury emissions.
104	Determination of beryllium emissions from stationary sources.
108	Determination of particulate and gaseous arsenic emissions.
EMTIC Test Method CTM-012.WPF	Chromium and copper emissions.

* Other approved EPA test methods may be substituted for the listed method unless the Department has adopted a specific test method for the air pollutant.

** Test for sulfuric acid mist only required when coal or tire derived fuel blends are burned at the facility.

A copy of this permit modification shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes. Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT MODIFICATION (including the FINAL permit Modification) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10-21-97 to the person(s) listed:

Mr. Carlos Rionda, Osceola Power L.P. *
Mr. David Buff, Golder Associates
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. David Knowles, SD
Mr. J. Koerner, PBCPHU

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kiri Fober 10-21-97
(Clerk) (Date)

Cogeneration Facility
Osceola Power L.P.
PSD-FL-197C and 0990331-006-AC
Pahokee, Palm Beach County

BACKGROUND

The applicant, Osceola Power L.P., constructed and began operating a 74 megawatt cogeneration facility in 1995. The facility consists of two identical spreader stoker boilers and associated equipment. The facility is permitted to burn primarily biomass (woodwaste and bagasse), with No. 2 fuel oil and coal used as supplemental fuels. Emission control equipment consists of an electrostatic precipitator (ESP) for particulate and heavy metals control, a selective non-catalytic reduction (SNCR) system for nitrogen oxides (NO_X)control, and an activated carbon injection system for mercury (Hg) control.

Ultimately the facility will provide the steam presently provided by the existing boilers at the adjacent Osceola Farms sugar mill. The boilers at that mill are scheduled for permanent shutdown by January 1, 1999.

A Best Available Control Technology (BACT) determination for NO_X control was not required at the time the permit was issued for the new boilers because potential emissions were estimated to be less than recent actual emissions from the boilers destined for shutdown. Very low NO_X emissions limits were set to avoid triggering New Source review for this pollutant. Osceola Power L.P. has met these limits but has encountered problems which may have been exacerbated by injection of excessive urea when trying to meet those limits. Among the problems are: relatively high plume opacity aggravated by formation of ammonium particulate species; increased deterioration of superheater tubes; and lower ESP particulate collection efficiency.

Osceola Power is requesting that the NO_X limits for the facility be relaxed. This results in a Significant Emission Increase (greater than 40 tons per year) in a PSD criteria pollutant at a Major Facility per Table 62-212.400-2. Relaxation of these limits will subject the facility to the PSD regulations, which requires a BACT determination pursuant to Rule 62-212.410, F.A.C. A project description, process description, and rule applicability are included in the Technical Evaluation and Preliminary Determination.

Following is the BACT determination proposed by the applicant:

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	PRESENT PERMITTED LIMIT lb/MMBtu heat input	PROPOSED BACT LIMIT lb/MMBtu heat input
Nitrogen Oxides:		
Biomass	0.12	0.15 lb/MMBtu
No. 2 Fuel Oil	0.12	0.15 lb/MMBtu
Coal	0.15	0.17 lb/MMBtu

The proposed increase in the emissions limits will result in an annual increase of approximately 150 tons per year (TPY) of NO_X. Osceola Power L.P. proposes to use the existing SNCR system to achieve the revised limits. The revised limits will be met by decreasing the ratio of urea injected into the furnace to NO_X present in the combustion gases. The applicant expects an amelioration of the present problems as a result of lowering use of urea.

DATE OF RECEIPT OF A BACT APPLICATION:

August 7, 1997

REVIEW GROUP MEMBERS:

A. A. Linero, New Source Review Section.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from this facility can be grouped into categories based upon the control equipment and techniques that are available to control emissions from these emission units. Using this approach, the emissions can be classified as follows:

- **Combustion Products** (e.g., SO_2, NO_X, PM). Controlled generally by good combustion of clean fuels or removal in add-on control equipment.
- **Products of Incomplete Combustion** (e.g., CO, VOC). Control is largely achieved by proper combustion techniques.

- **Other fuel contaminants** (fluorides, lead, mercury)

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Control of "non-regulated" air pollutants is considered in determining a BACT limit on a "regulated" pollutant (i.e., PM, SO_2, H_2SO_4, fluorides, etc.) if a reduction in "non-regulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

BACT POLLUTANT ANALYSIS

NITROGEN OXIDES (NO_X)

Oxides of nitrogen (NO_X) are generated during fuel combustion by oxidation of chemically bound nitrogen in the fuel (fuel NO_X) and by thermal fixation of nitrogen in the combustion air (thermal NO_X). As flame temperature increases, the amount of thermally generated NO_X increases. Fuel type affects the quantity and type of NO_X generated. Generally, biomass is low in nitrogen. Due to lower heating value and higher moisture, biomass causes lower flame temperatures and generates less thermal NO_X than oil or coal, which have higher fuel nitrogen content, and exhibit higher flame temperatures.

A review of EPA BACT/LAER Clearinghouse (BACT Clearinghouse) information indicates that NO_X emissions at many facilities burning primarily biomass are minimized by process control and good combustion practices, while several facilities employ the add-on technology of SNCR.

The applicant has proposed SNCR for control of NO_X emissions. SNCR involves the injection of either aqueous ammonia or urea into the boiler. The Osceola Power facility currently uses the NO_X OUT process whereby a urea-based reagent is injected into the flue gas. The urea selectively reduces the NO_X to nitrogen, carbon dioxide, and water. Generally, some unreacted urea in the flue gas results in emissions of ammonia (termed ammonia slip).

The applicant's proposed technology of SNCR is compared below with previous determinations documented by the BACT Clearinghouse.

BACT Clearinghouse Determinations

Determination:	Least Stringent	Most Stringent	Applicant Proposal
Year	1995	1992	1997
Limit (lb/MMBtu):	0.30	0.15	0.15

Based on information contained in the BACT/RACT/LAER Clearinghouse EPA database, all BACT determinations issued within the past 5 years for NO_X emissions from wood-fired boilers were reviewed. Most determinations were based on SNCR technology. A few determinations have been based on combustion control and boiler design and operation. Of the BACT determinations requiring SNCR, only a few have NO_X limits of less than 0.15 lb/MMBtu. A discussion of each of these is provided below:

- Multitrade LP - 0.1 lb/MMBtu; is a peaking boiler, not base load unit, and therefore is not directly comparable to Osceola.

- SAI Energy - 0.023 lb/MMBtu; is a fluidized bed unit, therefore not directly comparable to Osceola; also, was never constructed.
- Scott Paper - 43 ppm - Limit could not be met by Scott Paper; plan on raising to 86 ppm (similar to 0.15 lb/MMBtu).

BACT DETERMINATION RATIONALE:

According to the applicant and information from the BACT/LAER Clearinghouse, the range of NO_X BACT emission limits from recently-built wood-fired-boilers is 0.15 to 0.3 lb/MMBtu. This is consistent with determinations made by the Department for AES/Seminole Kraft and Wheelabrator Ridge of 0.29 and 0.14 lb/MMbtu respectively. Osceola Power has actually demonstrated that it can meet a limit of 0.12 lb/MMBtu while burning wood waste and bagasse, but has experienced operational problems including increased superheater tube failures, lower particulate removal efficiency, higher plume opacity, and disproportionately high ammonia emissions (slip). Ammonia is not a regulated air pollutant, but adds to the nitrogen load to the environment.

Identical units at Okeelanta Power are limited to 0.15 lb/MMBtu but experience less problems than those at Osceola Power. The most obvious difference in the operation at Osceola and Okeelanta is the amount of urea injected to accomplish NO_X removal.

Based on comparisons between Osceola and Okeelanta, the applicant has estimated the marginal cost of NO_X removal between 0.12 and 0.15 lb/MMBtu to be $25,600/ton. However the Department does not include costs related to lost production. Recalculation results in an estimate of approximately $13,000/ton which appears to be well in excess of typical cost effectiveness criteria used by the Department.

The limit previously established at Osceola when burning coal is 0.15 lb/MMBtu. The company has requested that this limit be raised to 0.17 lb/MMbtu, which is equal to that at Okeelanta.. The use of coal is limited to 4.4 percent of fuel use and neither Osceola nor Okeelanta has yet established any history of NO_X emissions or operational problems when firing or co-firing coal. At present there is no established limit for NO_X emissions when firing or co-firing tire-derived fuel (TDF). The applicant requested a limit when firing TDF of 0.17 lb/MMBtu.

The determination at Wheelabrator of 0.14 lb/MMBtu was made for the case when a fuel blend of 40 percent tires and 60 percent wood was fired. It is noted that Osceola Power agreed initially to a lower limit of 0.12 lb/MMBtu to avoid increases in NO_X emissions compared to the operation of certain existing boilers at Osceola Farms which are destined for permanent shutdown. This allowed the project to avoid being subjected to Non-Attainment Area New Source Review (NAANSR) and implementation of the Lowest Achievable Emissions Rate (LAER) irrespective of cost.

The area has since been redesignated as a maintenance area with respect to ozone. Therefore projects involving the ozone pre-cursors, VOCs and NO_X can be reviewed in accordance with PSD/BACT procedures instead of NAANSR/LAER procedures. The Department is reluctant to relax limits which were set to either comply with or "net out" of NAANSR. However, it appears that the impacts on ambient NO_X and ozone concentrations are negligible in this case. The energy, economic, and environmental impacts of the control method are apparently exacerbated by operating at the extreme limits of NO_X removal.

Selective Catalytic Reduction (SCR) may be a feasible control option for this type of unit. The technology is similar to SNCR, but involves injection of ammonia at a much lower temperature downstream of the furnace and in the presence of a catalyst, such as vanadium pentoxide. SCR has been demonstrated at coal-fired plants and could resolve concerns about the superheater tubes. However it would be costly and could add more factors to the problems experienced at the facility. The Department did not find any examples of SCR application to units fired primarily with woodwaste.

The air dispersion modeling analysis and the additional impact analysis presented by the applicant demonstrates that the increase in NO_X emissions will have insignificant effect upon ambient air concentrations in the area, and no adverse impact is predicted upon soils, vegetation or visibility in the area. Locally, there will be some improvement in visibility because of the reduction in ammonia salt emissions. Lower ammonia and ammonia salt emissions reduces the nitrogen load into the environment.

The maximum predicted annual average NO_X impact due to the proposed modification is 0.10 $\mu g/m^3$. The maximum impact upon the Everglades National Park PSD Class I area is 0.0013 $\mu g/m^3$, annual average. These impacts are well below specified significant impact levels of 1.0 $\mu g/m^3$ for the facility area, and 0.025 $\mu g/m^3$ for the Class I area.

BACT DETERMINATION BY DEP:

In consideration of all the facts and previous BACT determinations by the Department, the BACT determination for this proposed project is as follows:

A limit of 0.14 lb NO_X/MMBtu when firing wood waste, bagasse, or oil will be set. The justification is that it is equal to the most stringent demonstrated limit at a similar facility burning similar fuel. Although the cost effectiveness appears high, the Department believes that eventually optimization of operational and maintenance practices may reduce the problems and costs attributed to the control method without necessarily requiring further reductions in NO_X emission limits.

A BACT determination will not be set at this time for coal or TDF. This will be done when these fuels are burned or tested in the future. This will allow time for correction of the problems so that the effect of the control method can be separated from other practices at the facility. An example is the relocation of induced draft fans from upstream of the ESP to downstream of the ESP. In this case, the particulate control technique actually helped to remedy the problem of premature deterioration of the fans.

NO_X DETERMINATION

The BACT emission levels established by the Department are as follows:

POLLUTANT	PRESENT PERMITTED LIMIT	DEPARTMENT BACT LIMIT
	lb/MMBtu heat input	lb/MMBtu heat input
Nitrogen Oxides:		
Biomass	0.12	0.14 lb/MMBtu
No. 2 Fuel Oil	0.12	0.14 lb/MMBtu
Coal	0.15	n/a
Tire-Derived Fuel	n/a	n/a

COMPLIANCE

Compliance for NO_X will be determined by annual stack tests utilizing EPA Method 7 or 7E, and by the continuous NO_X monitors installed on each boiler. Compliance with the limit of 0.14 lb/MMBtu shall be on a 30-day rolling average.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E., Administrator, New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	Approved By:
for C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
10/22/97 Date:	10/23/97 Date:

Memorandum

Florida Department of
Environmental Protection

TO: Howard L. Rhodes

THRU: Clair Fancy *caf 10/22*
Al Linero *aaf 10/22*

FROM: Willard Hanks *WmH*

DATE: October 22, 1997

SUBJECT: Osceola Power L.P.
Modification of Permit
AIRS No. 0990331-006-AC (PSD-FL-197E)

Attached for your approval is the Best Available Control Technology (BACT) determination used to recently modify the construction permit for Osceola Power's cogeneration facilities located near Pahokee in Palm Beach County. No comments were submitted in response to the public notice for the proposed BACT and modification.

I recommend your approval and signature of the BACT.

WH/t

Attachment

Howard: F.Y.I. This NOx BACT is accomplished by SNCR and is equal to the one issued to Wheelabrator Ridge who burn similar material - 0.14 lb/mmBtu.

Al

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

September 17, 1997

WARNING NOTICE
AP -46- 97

RECEIVED
SEP 19 1997
BUREAU OF
AIR REGULATION

Carlos Rionda
Authorized Representative
Osceola Power Limited Partnership
P.O. Box 606
Pahokee, Florida 33476

Re: Opacity Excess Emissions, Osceola Cogeneration Facility.

Dear Mr. Rionda:

The Palm Beach County Health Department has received opacity excess emissions reports submitted for Osceola Cogeneration facility for the period July 1 through August 30, 1997.

A review of the reports reveal that there were excess opacity incidents occurring for at least 10 days during this period. On the days the excess emissions occurred, opacity exceeded the emission limiting standard of 20% opacity (six minutes average) except up to 27% for 6 minutes in any 1-hour period. The Health Department's review is tabulated in the attachment.

The cause of excess opacity given for most cases was that the ESP performance was impaired by the urea used to control NOx emissions. These excess emissions seem to have been caused by a design flaw rather than an equipment malfunction. The Health Department, therefore, believes that the Osceola Power Limited Partnership failed to comply with the emission limiting standard for opacity for this facility contained in the facility's construction permit and Federal Rule, 40CFR60, NSPS, Subpart Da.

Furthermore, Section 403.161 and 403.141, Florida Statutes provide that whoever commits a violation shall be liable to the state from any damage caused an civil penalties and/or fine up to $10,000.00 per day or portion thereof.

If your company wishes to pursue the administrative resolution of this matter please contact Mr. Ajaya K. Satyal at Palm Beach County Health Department, 901 Evernia Street, West Palm Beach, Florida 33402, telephone (561) 355-3070, within 10 days of receipt of this letter. A meeting will be arranged with the Health Department personnel and representative(s) of the Florida Department of Environmental Protection to discuss this matter.

Failure to respond to this notice could result in further enforcement action.

Sincerely,

Frank J. Gargiulo, P.E., R.S., Director
Division of Environmental Health & Engineering

FJG/AS/lh

cc: Vickie Coleman, Attorney, PBCHD
James Meriwether, OSPLP
David Knowles, P.E., DEP, Fort Myers
Jim Pennington, P.E., DARM, Tallahassee
Al Linero, P.E., DARM, Tallahassee
W. Hanks, BAR

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SEP 19 1997
BUREAU OF
AIR REGULATION

Excess Emissions Report Review, July 28-Aug 30, 1997.
Osceola Cogeneration Facility

Date and Unit	Opacity - Highest 6 Minutes Average	Cause Noted By Facility	PBCHD's Comment
July 28,1997 Unit 2	Opacity 38%	Field voltage effected by Urea	Does not appear to be an equipment malfunction..
July 28,1997 Unit 2	Opacity 31%	Equipment malfuction ESP performance degradation.	What caused the ESP degradation?
July 28, 1997 Unit 2	Opacity 31%	Equipment malfunction, ESP impaired by Urea.	Does not appear to be an equipment malfunction..
July 28, 1997 Unit 2	Opacity 27%	Equipment malfunction, ESP impaired by Urea.	Does not appear to be an equipment malfunction.
July 30, 1997 Unit 2	Opacity 28%	Equipment malfunction, ESP performance impaired by Urea	Does not appear to be an equipment malfunction.
Sept 31, 1997 Unit 2	Opacity 38%	Equipment malfunction, ESP performance impaired by Urea	Does not appear to be an equipment malfunction.
Aug 01, 1997 Unit 2	Opacity 38%	Equipment malfunction, ESP performance impaired by Urea	Does not appear to be an equipment malfunction.
Aug 11, 1997 Unit 2	Opacity 31%	Load change, high air flow, diminished ESP voltage.	If high air flow was caused by other equipment failure and that caused ESP voltage to drop, it can be considered an equipment malfunction. Please explain.
Aug 12, 1997 Unit 2	Opacity 31%	Load change, high air flow, diminished ESP voltage.	Does not appear to be an equipment malfunction.
Aug 18, 1997 Unit 2	Opacity 34%	Equipment malfunction, ESP performance impaired by Urea.	Does not appear to be an equipment malfunction.
Aug 30, 1997 Unit 2	Opacity 45%	Low ESP Voltage, ESP impaired by Urea, also load swing.	Does not appear to be an equipment malfunction.

September 8, 1997

Al Linero, PE
New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400
FAX: (904) 922-6979

RECEIVED
SEP 11 1997
BUREAU OF
AIR REGULATION

Re: Osceola Power Limited Partnership
Modification of AC50-269980 / PSD-FL-197A
Request to Revise Standards for CO, Hg, NOx, Pb, and SO_2, for Cogeneration Boilers

0990331-006-AC
PSD-FI-197E

Dear Mr. Linero:

We have reviewed the above referenced request and have the following comments:

Carbon Monoxide

After a review of the standards set for similar industries, the Health Department has no objection to the request to revise the averaging time to a 24 hour block average. We request that the permit specifically state compliance will be demonstrated by continuous monitor for each day of operation.

Mercury

The test results for mercury indicate that these emissions may vary greatly depending on the mercury content in the wood waste feed. The applicant states that no correlation can be made between the controlled emission rate and the activated carbon feed rate based on these past tests. However, a review of the test results indicates that only the controlled emissions are being measured during the testing; the uncontrolled mercury emissions are being *calculated* based on sampling and analysis of the wood waste and feed rate. The Health Department believes this leads to inaccurate results. Before establishing a new, higher mercury emissions limit, we request the following:

- Conduct a series of simultaneous mercury emissions tests on the inlet and outlet at varying carbon feed rates to establish a relationship between the control device and mercury emissions.
- Based on the new test results, establish a minimum carbon feed rate. Continuously monitor this feed rate to determine compliance.
- Annually test inlet/outlet at minimum carbon feed rate to check relationship.

Lead

If lead emissions are being controlled with a 97% efficiency, but the emissions limit is still being exceeded, then the assumption is that the lead content of the wood waste is higher than originally estimated. Rather than increase the lead emissions limit, the Health Department asks for better control and screening of the wood waste materials being burned in the boilers.

Nitrogen Oxides (NOx)

The following summarizes my understanding of the NOx issue:

Osceola originally requested a lower NOx limit (0.12 lb/mmBTU, biomass) than Okeelanta Power (0.15 lb/mmBTU, biomass) in order to escape a BACT determination at that time. Increased NOx emissions of 39.3 TPY were kept just below the 40 TPY significance level. This lower emissions rate required a 40% higher urea injection rate to obtain only a 7.5% reduction in NOx emissions. The high urea injection rate lead to the following problems:

- Increased ammonia slip resulting in ammonia bisulfate formation which, in turn, lead to fowling of the air preheater, fowling of the electrostatic precipitator, and eventually excess opacity.
- Increased superheater tube failure resulting in additional boiler down time, increased emissions during startup and shutdown, and lost power generation and revenues
- Substantially increased expense of urea injection.

The applicant has stated that an inspection by a private consultant concluded that the increase in opacity is the result of a decrease in the resistivity of the flue gas particulate due to the high ammonia and moisture levels. Given the reduced number of these problems at the Okeelanta facility, this conclusion appears to be reasonable. The modeling results indicate that the increased NOx emissions would have an insignificant effect on the ambient air concentration. The only remaining question that the Health Department has is: *Would the PSD/BACT permitting process have been different if the application were processed with the newly proposed NOx limit back in 1993?*

Sulfur Dioxide

The request proposes the following SO_2 standards:

- 0.10 lb/mmBTU of heat input, on a 24-hour average for bagasse and wood waste *(no change)*
- 0.02 lb/mmBTU of heat input, on an annual basis for bagasse *(no change, at this time?)*
- 0.05 lb/mmBTU of heat input, on an annual basis for wood waste *(revision)*

This request is based on additional information not present during the initial application including specific fuel analyses and CEM data. The applicant has also requested a decrease in coal firing to 14,883 tons per year in order to maintain potential SO_2 emissions below 339 tons per year. The Health Department again reminds the applicant of the specific county zoning conditions regulating actual SO_2 emissions from the combined Osceola and Okeelanta cogeneration facilities.

Consideration of Tire Derived Fuels (TDF)

This request includes comments and calculations considering TDF. The application for modification states that the permit modification is being held in abeyance pending test results. It is the position of the Health Department that TDF is not yet an approved fuel and should not be considered in this request. The Department has only granted a temporary test burn period in which to gather data. Based on the test results, TDF *may or may not* be approved as a permanent fuel. It is our understanding that another request for permit modification must be submitted with the test results. Also, the current emissions standards are specific to the type of fuel being burned. Burning TDF may create yet another emissions standard for several of these pollutants. The Health Department requests that the application exclude TDF at this time.

Thank you for the opportunity to comment on this application. If you have any questions, please contact me at the numbers below.

Sincerely,

For the Division Director
Environmental Health and Engineering

Jeffery F. Koerner

Jeffery F. Koerner, PE
Air Pollution Control Section
Phone: (561) 355-4549 SunCom: 273-4549
FAX: (561) 355-2442

cc: L. Martin Hodgkins, Sr. Director
Zoning Division
Palm Beach County Planning, Zoning, & Building
100 Australian Avenue
West Palm Beach, FL 33406

David Buff, PE
Golder Associates Inc.
Fax: (352) 336-6603

Ed Walker, Plan Review Section
Palm Beach County Health Department

Filename: OSC_PSD.LTR

OSCEOLA POWER

September 23, 1997

State of Florida
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

Attn: Mr. A. A. Linero, P.E.
Administrator

Re: Osceola Power Limited Partnership
DRAFT Permit Modification No. 0990331-006-AC,
(PSD-FL-197E)
Proof of Publication

Dear Mr. Linero:

The "Public Notice of Intent to Issue Air Construction Permit Modification" for Osceola Power was published in the Palm Beach Post on September 12, 1997. Please see the enclosed Proof of Publication for that notice.

Sincerely,

J. M. M

James M. Meriwether
Environmental Manager

cc: C. Rionda
S. Sorrentino
M. Keegan
M. Golden
D. Dee
D. Buff

CC: W. Hanks, BAR
D. Buff, Golder assoc.
EPA
NPS
SD
Palm Bch. Co.

RECEIVED
SEP 26 1997
BUREAU OF
AIR REGULATION

THE PALM BEACH POST

Published Daily and Sunday
West Palm Beach, Palm Beach County, Florida

PROOF OF PUBLICATION

STATE OF FLORIDA
COUNTY OF PALM BEACH

Before the undersigned authority personally appeared **Chris Bull** who on oath says that she is **Classified Advertising Manager** of The Palm Beach Post, a daily and Sunday newspaper published at West Palm Beach in Palm Beach County, Florida; that the attached copy of advertising, being a **Notice** in the matter of **Intent to Issue air const. permit modif.** in the - - - Court, was published in said newspaper in the issues of **September 12, 1997.**

Affiant further says that the said The Post is a newspaper published at West Palm Beach, in said Palm Beach County, Florida, and that the said newspaper has heretofore been continuously published in said Palm Beach County, Florida, daily and Sunday and has been entered as second class mail matter at the post office in West Palm Beach, in said Palm Beach County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she/he has neither paid nor promised any person, firm or corporation any discount rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Chris Bull

Sworn to and subscribed before me 15 day of September A.D. 1997

Karen McLinton

Personally known **XX** or Produced Identification ________
Type of Identification Produced ________

Karen McLinton
Notary Public, State of Florida
Commission No. CC 591337
My Commission Exp. 11/15/2000
1-800-3-NOTARY Fla. Notary Service & Bonding Co.

NO. 393371
PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION
STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
DRAFT Permit Modification No. 0990331-006-AC, PSD-FL-197E
Osceola Cogeneration Facility
Palm Beach County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to Osceola Power Limited Partnership, for increases in emissions from the cogeneration facility located at U.S. Highway 98 and Hatton Highway in Pahokee, Palm Beach County. A Best Available Control Technology (BACT) determination was required for nitrogen oxides pursuant to Rules 62-212.400 and 410, F.A.C., Prevention of Significant Deterioration (PSD). The facility consists of two multiple fuel boilers which produce steam for use by the adjacent Osceola Farms sugar mill and up to 74 megawatts of electricity. The applicant's name and address are: Osceola Power Limited Partnership, Post Office Box 606, Pahokee, Florida 33476. The permit is to revise allowable limits for lead (Pb), sulful dioxide (SO2), nitrogen oxides (NOx) and Mercury (Hg) when burning woodwaste; revise carbon monoxide (CO) and NOx while burning fuel oil; and revise the averaging time for CO for all uels. Annual emissions will increase only for Pb and NOx, but only the NOx increase is significant with respect to PSD. Emissions of NOx will increase by approximately 100 tons per year (TPY). Control is accomplished by injection of urea into the furnace through Selective Non-Catalytic Reduction (SNCR). The proposed emission limit is 0.14 pounds of NOx per million Btu of heat input (lb/MMBtu) when burning woodwaste or fuel oil and is among the lowest in the country for multiple fuel boilers. The new limit will also reduce ammonia emissions (slip), improve electrostatic precipitator efficiency, and reduce plume opacity. An air quality impact analysis was conducted. The maximum impact is below the significant impact level of 1 microgram per cubic meter (pg/m3). Emissions from the facility will consume PSD increment but will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The maximum predicted PSD Class II NOx increment consumed by this project will be 0.4 percent of the allowable increment of 25 pg/m3 for all projects in the area. The project has an insignificant impact on the Everglades Class I area for the NOx annual averaging time.

The Department will issue the FINAL Permit Modification, in accordance with the conditions of the DRAFT Permit Modification unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed DRAFT Permit Modification issuance action for a period of 30 (thirty) days from the date of publication of this Notice. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit Modification, the Department shall issue a Revised DRAFT Permit Modification and require, if applicable, another Public Notice. The Department will issue FINAL Permit Modification with the conditions of the DRAFT Permit Modification unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S. The procedures for petitioning for a hearing are set forth below. Mediation is not available for this action. A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 850/488-9370, fax: 850/487-4938. Petitions must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28.5.207 of the Florida Administrative Code. A petition must contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the Department's action or proposed action addressed in this notice of intent. Because the administrative hearing process is designed to forumulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/488-1344
Fax: 850/922-6979

Dept. of Environmental Protection
South District Office
2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901
Telephone: 813/332-6975
Fax: 813/332-6969

Palm Beach County Public Health Unit
901 Evernia Street
Post Office Box 29
West Palm Beach, Florida 33401
Telephone: 561/355-3070
Fax: 561/355-2442

The complete project file includes the Draft Permit Modification, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 650/488-1344, for additional information.

PUB: The Palm Beach Post September 12, 1997

Department of
Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

September 8, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Carlos Rionda, Authorized Representative
Osceola Power Limited Partnership
P.O. Box 606
Pahokee, Florida 33476

Re: DRAFT Permit Modification No. 0990331-006-AC (PSD-FL-197E)
74 Megawatt Cogeneration Facility

Dear Mr. Rionda

Enclosed is one copy of the Draft Air Construction Permit Modification for the cogeneration facility located at U.S. Highway 98 and Hatton Highway in Pahokee, Palm Beach County. The Department's Intent to Issue Air Construction Permit Modification and the "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION" must be published within 30 (thirty) days of receipt of this letter. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit modification.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Mr. Linero at 850/488-1344.

Sincerely,

C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/aal

Enclosures

In the Matter of an
Application for Permit Modification by:

Osceola Power Limited Partnership
Post Office Box 606
Pahokee, Florida 33476
/

DRAFT Permit Modification No. 0990331-006-AC
Draft PSD Permit No. PSD-FL-197E
Osceola Cogeneration Facility
Palm Beach County

INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification (copy of DRAFT Permit modification attached) for the proposed project, as detailed in the application specified above and attached Technical Review and Preliminary determination, for the reasons stated below.

The applicant, Osceola Power Limited Partnership, applied on August 7, 1997 to the Department for an air construction permit modification for its cogeneration facility located at U.S. Highway 98 and Hatton Highway, Pahokee, Palm Beach, County. The request is to revise permitted emission limits for two biomass and coal-fired boilers to reflect achievable emissions based on actual operations.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit modification, including a review for the Prevention of Significant Deterioration and a determination of Best Available Control Technology for the control of nitrogen oxides, is required to revise the permitted emission limits as proposed.

The Department intends to issue this air construction permit modification based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION". The notice shall be published one time only within 30 (thirty) days in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-1344; Fax 850/ 922-6979) within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit modification pursuant to Rule 62-103.150 (6), F.A.C.

The Department will issue the FINAL Permit Modification, in accordance with the conditions of the enclosed DRAFT Permit Modification unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed DRAFT Permit Modification issuance action for a period of 30 (thirty) days from the date of publication of "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION." Written comments [and requests for public meetings] should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit Modification, the Department shall issue a Revised DRAFT Permit Modification and require, if applicable, another Public Notice.

The Department will issue the permit modification with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S. The procedures for petitioning for a hearing are set forth below. Mediation is not available for this action.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 850/488-9730, fax: 850/487-4938. Petitions must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the action or proposed action addressed in this notice of intent.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION (including the PUBLIC NOTICE, and DRAFT permit modification) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 9-9-97 to the person(s) listed:

Mr. Carlos Rionda, Osceola Power L.P. *
Mr. Daniel Thompson, Berger Davis & Singerman *
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. David Buff, P.E., Golder Associates
Mr. David Knowles, SD
Mr. James Stormer, PBCPHU

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

9-9-97
(Clerk) (Date)

P 265 659 451

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Carlos Rionda	
Street & Number Osceola Power	
Post Office, State, & ZIP Code Pahokee Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 9-9-97 0990331-006-AC PSD-FL-~~FE~~197E	

PS Form 3800, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Carlos Rionda, AR
Osceola Power, LP
P O Box 666
Pahokee, Fl 33476

4a. Article Number
P 265 659 451

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
9-11-97

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Anthony McPhee

PS Form **3811,** December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DRAFT Permit Modification No. 0990331-006-AC, PSD-FL-197E

Osceola Cogeneration Facility
Palm Beach County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to Osceola Power Limited Partnership, for increases in emissions from the cogeneration facility located at U.S. Highway 98 and Hatton Highway in Pahokee, Palm Beach County. A Best Available Control Technology (BACT) determination was required for nitrogen oxides pursuant to Rules 62-212.400 and 410, F.A.C., Prevention of Significant Deterioration (PSD). The facility consists of two multiple fuel boilers which produce steam for use by the adjacent Osceola Farms sugar mill and up to 74 megawatts of electricity. The applicant's name and address are: Osceola Power Limited Partnership, Post Office Box 606, Pahokee, Florida 33476.

The permit is to revise allowable limits for lead (Pb), sulfur dioxide (SO_2), nitrogen oxides (NO_X) and mercury (Hg) when burning woodwaste; revise carbon monoxide (CO) and NO_X while burning fuel oil; and revise the averaging time for CO for all fuels. Annual emissions will increase only for Pb and NO_X, but only the NO_X increase is significant with respect to PSD.

Emissions of NO_X will increase by approximately 100 tons per year (TPY). Control is accomplished by injection of urea into the furnace through Selective Non-Catalytic Reduction (SNCR). The proposed emission limit is 0.14 pounds of NO_X per million Btu of heat input (lb/MMBtu) when burning woodwaste or fuel oil and is among the lowest in the country for multiple fuel boilers. The new limit will also reduce ammonia emissions (slip), improve electrostatic precipitator efficiency, and reduce plume opacity.

An air quality impact analysis was conducted. The maximum impact is below the significant impact level of 1 microgram per cubic meter ($\mu g/m^3$). Emissions from the facility will consume PSD increment but will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The maximum predicted PSD Class II NO_X increment consumed by this project will be 0.4 percent of the allowable increment of 25 $\mu g/m^3$ for all projects in the area The project has an insignificant impact on the Everglades Class I area for the NO_X annual averaging time.

The Department will issue the FINAL Permit Modification, in accordance with the conditions of the DRAFT Permit Modification unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed DRAFT Permit Modification issuance action for a period of 30 (thirty) days from the date of publication of this Notice. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit Modification, the Department shall issue a Revised DRAFT Permit Modification and require, if applicable, another Public Notice.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

The Department will issue FINAL Permit Modification with the conditions of the DRAFT Permit Modification unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S. The procedures for petitioning for a hearing are set forth below. Mediation is not available for this action.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 850/488-9370, fax: 850/487-4938. Petitions must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the Department's action or proposed action addressed in this notice of intent.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept .of Environmental Protection	Dept. of Environmental Protection	Palm Beach County Public Health Unit
Bureau of Air Regulation	South District Office	901 Evernia Street
111 S. Magnolia Drive, Suite 4	2295 Victoria Avenue, Suite 364	Post Office Box 29
Tallahassee, Florida, 32301	Fort Myers, Florida 33901	West Palm Beach, Florida 33401
Telephone: 850/488-1344	Telephone: 813/332-6975	Telephone: 561/355-3070
Fax: 850/922-6979	Fax: 813/332-6969	Fax: 561/355-2442

The complete project file includes the Draft Permit Modification, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-1344, for additional information.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

OSCEOLA POWER LIMITED PARTNERSHIP

74 MW Cogeneration Facility
Pahokee, Florida
Palm Beach County

Air Construction Permit No. 0990331-006-AC
PSD-FL-197E
[Modifies AC50-269980]

Boilers A and B

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

September 8, 1997

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Osceola Power Limited Partnership
Post Office Box 606
Pahokee, FL 33476

Authorized Representative: Mr. Carlos Rionda, General Manager

1.2 Reviewing and Process Schedule

08-07-97: Meeting with Osceola Power
08-07-97: Date of Receipt of Application
09-08-97: Issuance of Intent

2. FACILITY INFORMATION

2.1 Facility Location

Osceola Power Limited Partnership cogeneration facility is located off U.S. Highway 98 at Hatton Highway, East of Pahokee, Palm Beach County, next to the Osceola Farms sugar mill. This site is approximately 120 kilometers north of the Everglades National Park, a Class I PSD Area. The UTM coordinates of this facility are Zone 17; 544.2 km E; 2968.0 km N.

2.2 Standard Industrial Classification Code (SIC)

Major Group No.	49	Electric Generation
Industry No.	4911	External Combustion Boiler - Electric Generation

2.3 Facility Category

This 74 megawatt electric cogeneration facility is allowed to burn biomass (bagasse and wood waste material), No. 2 fuel oil, and low sulfur coal in two Zurn spreader-stoker boilers. It includes fuel and ash handling equipment and steam turbines. Steam generated by the units is used at the nearby sugar mill while electricity is sold offsite.

Osceola Power is classified as a major or Title V source of air pollution because emissions of several regulated air pollutants, including particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC) exceed 100 TPY.

This industry is included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for various criteria pollutants, the facility is also a major facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications at the facility resulting in emissions increases greater than 40 TPY of NO_X or SO_2 require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.410, F.A.C.

08-05-97

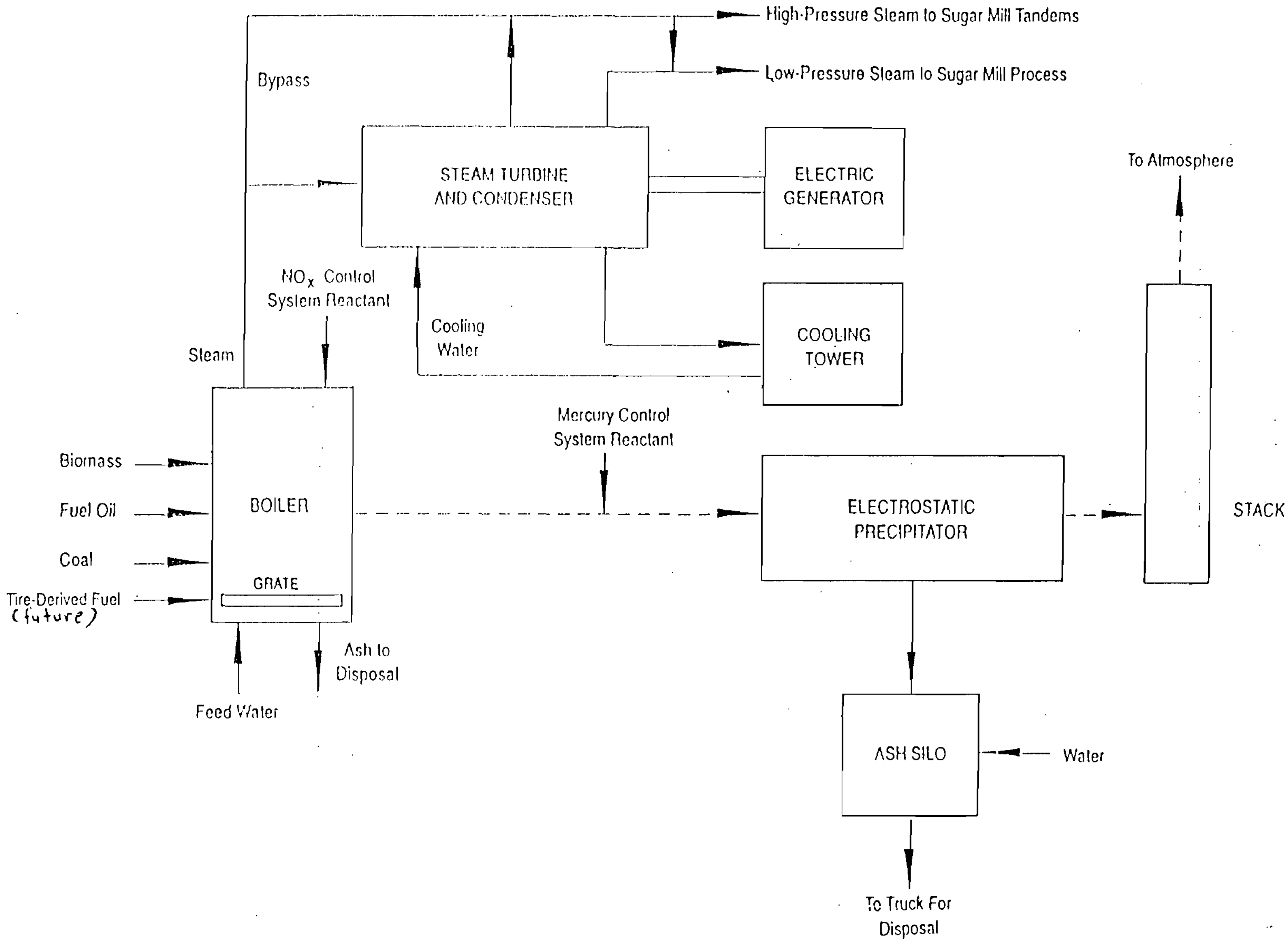

Figure 1
Simplified Flow Diagram for Osceola Power Cogeneration Facility

Golder Associates

3. PROCESS DESCRIPTION

The source is a 74 MWe (gross) capacity biomass/coal-fired cogeneration facility consisting of two steam boilers and one steam turbine and associated equipment. Each boiler is capable of producing an average of 506,000 lbs/hr steam. During the sugar processing season, the cogeneration facility is to provide steam to the existing Osceola Farms sugar mill by burning primarily bagasse, which is the cellulose fiber coproduct resulting from the sugar cane grinding process, while also generating electricity. During the off-season, the cogeneration facility will burn primarily wood waste to generate electricity. The facility is also permitted to burn low sulfur coal and low sulfur fuel oil.

The maximum heat input to each of the two boilers is 760 million Btu per hour (MMBtu/hr) when firing biomass, 600 MMBtu/hr when firing No. 2 fuel oil, and 530 MMBtu/hr when firing low sulfur coal. Maximum annual heat input to the entire facility is limited to 8.208×10^{12} Btu/yr. Maximum annual coal burning will be limited to 14,883 tons per year (TPY), which is approximately 4.4 percent of the total maximum annual heat input to the facility.

Air pollution control equipment serving each boiler consists of an electrostatic precipitator (ESP) to control particulate matter (PM), including heavy metal emissions, a selective non-catalytic reduction (SNCR) system for the control of NO_x emissions, and a carbon injection system for mercury (Hg) control. A simplified process flow diagram of the cogeneration facility is presented in Figure 1.

4. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power	Boiler A and associated equipment
002	Power	Boiler B and associated equipment

No physical modifications are related to the proposed project. The modification relates to revisions of conditions in the original air construction permit issued in September, 1993. The project primarily consists of an operational change related to the amount of urea used to control NO_X emissions.

The requested modifications consist of revisions to the allowable limits for lead (Pb), SO_2, NO_X, and Hg when burning waste wood; revision of CO and NO_X limits when burning fuel oil and coal: and revision of the averaging time for the CO limits for all fuels.

The requested changes in the permit limits will not increase permitted annual emissions of PSD regulated pollutants, except for NO_x and small increases in the annual emissions of lead. Emission increases for Pb are below the significant emission level of 0.6 TPY per Table 62-212.400-2, F.A.C. and do not require PSD or nonattainment new source review. However, PSD review is required for NO_X since emissions will increase by more than 40 TPY.

5. RULE APPLICABILITY

The two boilers are subject to federal new source performance standards (NSPS) for electric utility boilers (40 CFR 60, Subpart Da), incorporated by reference in Rule 62-204.800, F.A.C. Because the facility will burn yard waste potentially originating from residential sources, the boilers are also subject to a reporting and record keeping requirements of under 40 CFR 60, Subparts Ea and Cb, incorporated by reference in Rule 62-204.800, F.A.C. The existing permits limit combustion of municipal solid waste (MSW), including yard waste, to 30 percent (weight basis) on a calendar quarter basis. Therefore no provisions of Subparts Ea and Cb will apply to the facility other than the record keeping and reporting requirements.

The proposed project is subject to permitting, preconstruction review, emissions limits and compliance requirements under the provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility is located in Palm Beach County, an area designated as attainment or maintenance for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD), because the potential emission increases for NO_x exceed the significance emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C. PSD review includes a determination air quality impacts and a determination of Best Available Control Technology (BACT).

The emission units affected by this permit modification shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules:

Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.360	Designation of Prevention of Significant Deterioration Areas
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-296.510	RACT for Major NOx/VOC Emitting Sources
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed Osceola Power modification will increase allowable annual emissions of the following PSD pollutants (Table 212.400-2, F.A.C.): nitrogen oxides and lead. Emissions limits for individual fuels and averaging times are being revised for SO_2, CO and mercury; however, annual emissions remain unchanged. The permitted and requested allowable emissions for this modification are summarized in the following table.

6.2 Emission Summary

Emissions From Boilers A and B (total)

Pollutant	Current Allowable (tons/yr)	Requested Allowable (tons/yr)	Net Increase (tons/yr)	PSD Significant Level (tons/yr)
SO_2	339.0	339.0	0	40
NOx	477.1	626.9	149.8	40
CO	1,436.4	1,436.4	0	100
Mercury	0.0168	0.0168	0	0.1
Lead	0.011	0.27	0.26	0.60

6.3 Control Technology Review

The Osceola Power facility has modern emissions controls consisting of ESP's for particulate and heavy metals, SNCR for NO_X, and carbon injection for mercury control. Because the facility will not emit significantly more SO_2 than the sugar mill boilers it will replace, no control equipment was required except for relatively low sulfur limits for in the fuels burned.

The only pollutant of concern with respect to the present permitting action is NO_X, emissions of which will increase by 149 TPY. Osceola Power's request is to revise their NO_X limit from 0.12 pounds per million Btu (lb/MMBtu) to 0.15 lb/MMBtu while burning oil, or biomass (bagasse and wood waste) and from 0.15 to 0.17 while burning coal or, eventually, tire-derived fuel (TDF). Biomass fired in the boilers has low nitrogen content, typically less than 0.5 percent (dry basis). As a result, fuel NO_X is low from biomass-fired boilers. Thermal NO_X is the primary emission from such boilers. In general, biomass-fired boilers emit less NO_X than fossil fuel-fired boilers.

Osceola Power utilizes a urea-based selective non-catalytic reduction (SNCR) system which can control NO_x emissions while firing biomass to 0.12 lb/MMBtu. This level of control is more stringent than any Best Available Control Technology (BACT) determination made by the Department at similar facilities in the state. The lowest emission rate pursuant to BACT was determined for Wheelabrator Auburndale and is equal to 0.14 lb/MMBtu.

According to the applicant, operating at 0.12 lb/MMBtu requires injection of urea well in excess of operational ranges typically encountered for this technology. According to the company, this has exacerbated problems related with premature superheater tube failure, excessive opacity, inefficient ESP particulate collection efficiency, and ammonia emissions (slip).

Further details are presented in the draft BACT determination issued concurrently with this review. The Department believes that a NO_X limit equal to 0.14 lb/MMBtu is more appropriate. Emissions increases of NO_X will, therefore, be less than 100 TPY.

6.4 Air Quality Analysis

6.4.1 Introduction

The proposed project will increase emissions of NO_X in excess of PSD significant amounts. The air quality impact analyses required by the PSD regulations for this pollutant includes:

- An analysis of existing air quality;
- A significant impact analysis;
- A PSD increment analysis;
- An Ambient Air Quality Standards (AAQS) analysis; and
- An analysis of impacts on soils, vegetation, visibility,and growth-related impacts.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The significant impact, PSD increment, and AAQS analyses depend on air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on the required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A discussion of the required analyses follows.

6.4.2 Analysis of Existing Air Quality and Determination of Background Concentrations

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. This monitoring requirement may be satisfied by using previously existing representative monitoring data, if available. An exemption to the monitoring requirement may be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimus concentration. In addition, if an acceptable monitoring method for the specific pollutant has not been established by EPA, monitoring may not be required.

If preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants with established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from previously existing representative monitoring data. These background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling.

The table below shows that NO_2 impacts due to the proposed project are predicted to be less than the de minimus levels; therefore, preconstruction ambient air quality monitoring is not required for this pollutant.

Maximum Project Air Quality Impacts for Comparison to the De Minimus Ambient Levels

Pollutant	Averaging Time	Maximum Predicted Impact (ug/m^3)	Impact Greater Than De Minimus?	De Minimus Level (ug/m^3)
NO_2	Annual	0.1	NO	14

6.4.3 Models and Meteorological Data Used in Significant Impact, PSD Increment and AAQS Analyses

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) station at West Palm Beach, Florida. The 5-year period of meteorological data was from 1987 through 1991. This NWS station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

Since five years of data were used in ISCST3, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility and if there are significant impacts from the project on any PSD Class I area, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

6.4.4 Significant Impact Analysis

Initially, the applicant conducted modeling using only the proposed project's increase in emissions. Receptors were placed within 6 km of the facility, which is located in a PSD Class II area, and in the Everglades National Park (ENP) which is a PSD Class I area located approximately 120 km to the south of the project at its closest point. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compared maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project were predicted in the vicinity of the facility or in the ENP. The tables below show the results of this modeling. The radius of significant impact, if any, for each pollutant and applicable pollutant averaging time is also shown in the tables below.

Maximum Project Air Quality Impacts for Comparison to the PSD Class II Significant Impact Levels in the Vicinity of the Facility

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?	Radius of Significant Impact (km)
NO_X	Annual	0.1	1	No	0.0

Maximum Project Air Quality Impacts in the ENP for Comparison to the PSD Class I Significant Impact Levels

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	NPS Significant Impact Level (ug/m^3)	Significant Impact?
NO_2	Annual	0.0013	0.03	No

As shown in the tables the maximum predicted air quality impacts due to NO_x emissions from the proposed project are less than the significant impact levels in the vicinity of the facility. The maximum predicted air quality impacts in the Class I area due to NO_x emissions are also less than the significant impact level for the annual averaging time. Therefore, the applicant was not required to perform further NO_2 modeling in the vicinity of the facility or in the Class I area.

6.5 Additional Impacts Analysis

6.5.1 Impacts On Soils, Vegetation, And Wildlife

The maximum ground-level concentrations predicted to occur for NO_x as a result of the proposed project are below significant impact levels, and therefore will not significantly contribute to ambient air quality. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area. An air quality related values (AQRV) analysis was done by the applicant for the Class I area. No significant impacts on this area are expected.

6.5.2 Impact On Visibility

Visual Impact Screening and Analysis (VISCREEN), the EPA-approved Level I visibility computer model, was used to estimate the impact of the proposed project's increased NO_x emissions on visibility in the ENP. The results indicate that the maximum visibility impacts do not exceed the screening criteria inside or outside this area. As a result, there is no significant impact on visibility predicted for this Class I area. In addition a regional haze analysis was done. This analysis predicted no adverse impacts upon regional haze.

Locally, there will be an improvement in plume opacity. This is because less urea will be injected in the future and less excess ammonia will be available to contribute to particulate formation from species such as ammonium bisulfate and ammonium chloride.

6.5.3 Growth-Related Air Quality Impacts

There will be no growth-related impacts because no physical or operational modifications will occur and production will not change as a result of this permit action.

6.5.4 Air Toxics Air Quality Impacts

The maximum predicted impacts of regulated and non-regulated toxic air pollutants that are proposed to be emitted by the project are all less than the Department's draft annual Ambient Reference Concentrations (ARC).

7. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by Osceola Power, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations provided the Department's BACT is implemented.

Permit Reviewer: A. A. Linero, P.E.

DRAFT

October xx, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Carlos Rionda, General Manager
Osceola Power Limited Partnership
Post Office Box 606
Pahokee, Florida 33476

Re: Permit Modification No. 0990331-006-AC (PSD-FL-197C)
74 Megawatt Cogeneration Facility

Dear Mr. Rionda:

The Department has reviewed your application dated August 6, 1997 to modify the original construction permit for the Osceola Cogeneration Facility. The application is to revise emission limits for carbon monoxide (CO), lead (Pb), mercury (Hg), sulfur dioxide (SO_2), and nitrogen oxides (NO_X). An evaluation for the Prevention of Significant Deterioration (PSD) was performed and a Best Available Control Technology determination was conducted for NO_X. Construction permit No. AC50-269980 (PSD-FL-197B) is hereby modified as follows:

SPECIFIC CONDITION NO. 15.

The combined use of coal and oil shall be less than 25 percent of the total heat input to ~~this cogeneration facility~~ each boiler on a calendar quarter basis. The consumption of low sulfur coal shall not exceed ~~5.4 percent of the total heat input to each boiler unit in any calendar quarter. The plant shall not burn more than 18,221~~ 14,883 tons ~~of coal~~ during any 12-month period (12-month rolling average).

SPECIFIC CONDITION NO. 16.

The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, beryllium content (coal only), sulfur content, and equivalent SO_2 emission rate (in lb/MMBtu) of each fuel oil and coal delivery shall be kept in a log for at least two years. For each calendar month, the calculated SO_2, mercury, and lead emissions and 12-month rolling average shall be determined (in tons) and kept in a log.

SPECIFIC CONDITION NO. 19.

Visible emissions from any cogeneration boiler shall not exceed 20 percent opacity, 6-minute average, except up to 27 percent opacity is allowed for up to 6 minutes in any one hour period. Based on a maximum heat input to each boiler of 760 MMBtu/hr for biomass fuels, 600 MMBtu/hr for No. 2 fuel oil, and 530 MMBtu/hr for coal, stack emissions shall not exceed any limit shown in the following table:

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	EMISSION LIMIT (per boiler) [d]						Total [e]
	Biomass		No. 2 Oil		Bit. Coal		Two Boilers
Pollutant	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(TPY)
Particulate (TSP)	0.03	22.8	0.03	18.0	0.03	15.9	123.1
Particulate (PM_{10})	0.03	22.8	0.03	18.0	0.03	15.9	123.1
Sulfur Dioxide							
3-hour average	---	---	---	---	1.2	636.0	---
24-hour average	0.10	76.0	0.05	30.0	1.2	636.0	---
Annual average	~~0.02 a~~				1.2 a	---	339.0 f
(Bagasse)	0.02 a b	---	---	---			
(Woodwaste)	0.05 a c						
Nitrogen Oxides							
Annual average	~~0.12~~ 0.14	~~88.2~~ 103 a	~~0.12~~ 0.14 a	~~72.0~~ 84.0 a	0.15 a	79.5 a	~~477.1~~ 577
Carbon Monoxide							
~~8~~24-hr average	0.35	266.0	~~0.2~~ 0.35	~~120~~ 210.0	~~0.2~~ 0.35	~~106.0~~ 185.5	1,436.4
Volatile Organic Compounds	0.06 b 0.04 c	45.6 b 30.4 c	0.03	18.0	0.03	15.9	219.2
Lead	~~2.7 x 10 -6 b~~	~~0.002~~	8.9 x 10 -7	0.0005	5.1 x 10 -6	0.0027	~~0.011~~ 0.27 f
(Bagasse)	2.7 x 10 -6 b	0.002					
(Wood Waste)	1.6 x 10 -4 c	0.12					
Mercury	~~5.7 x 10 -6 b~~ 3.5 x 10 -6 b ~~0.29 x 10 -6c~~ 4.0 x 10 -6 c	~~0.0043 b~~ 0.0027 b 0.00022 c 0.0030 c	2.4 x 10 -6	0.0014	8.4 x 10 -6	0.0045	0.0168 f
Beryllium	---	---	3.5 x 10 -7	0.0002	5.9 x 10 -6	0.0031	0.0013
Fluorides	---	---	6.3 x 10 -6	0.004	0.024	12.7	5.25
Sulfuric Acid Mist	0.005	3.72	0.0025	1.5	0.010	5.3	6.0

[a] Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.

[b] Emission limit for bagasse. Subject to revision after testing pursuant to Specific Conditions Nos. 23 and 24.

[c] Emission limit for woodwaste. Subject to revision after testing pursuant to Specific Conditions Nos. 23 and 24.

[d] The emission limit shall be prorated when more than one type of fuel is burned in a boiler.

[e] Limit heat input from No. 2 fuel to less than 25% of total heat input on a calendar quarter basis and coal to ~~18,221~~ 14,883 tons during any 12-month period. Combined heat input of coal and oil shall be less than 25% of the total heat input on a calendar quarter basis.

[f] Compliance based on a 12-month rolling average.

The permittee shall comply with the excess emissions rule contained in Rule 62-296.210, F.A.C. In addition, the permittee is allowed excess emissions during startup conditions, provided such excess emissions do not exceed a duration of four hours, and such emissions in excess of two hours do not exceed six (6) times per year.

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SPECIFIC CONDITION NO. 21 STACK TESTING.

a. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct emission compliance tests for all air pollutants listed in Specific Condition No. 19 (including visible emissions). Tests shall be conducted during normal operations (i.e., within 10 percent of the permitted heat input). The permittee shall furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The emission compliance tests will be conducted in accordance with the provisions of 40 CFR 60.46a.

b. Compliance with emission limitations for each fuel stated in Specific Condition No. 20 above shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), continuous emissions monitoring data, or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), or any other method as approved by the Department, in accordance with F.A.C. Rule 17-297.620. A test protocol shall be submitted for approval to the Bureau of Air Regulation at least 90 days prior to testing.

EPA Method*	For Determination of
1	Selection of sample site and velocity traverses.
2	Stack gas flow rate when converting concentrations to or from mass emission limits.
3 or 3A	Gas analysis when needed for calculation of molecular weight or percent O_2.
4	Moisture content when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits.
5	Particulate matter concentration and mass emissions.
201 or 201A	PM_{10} emissions.
6, 6C, or 19	Sulfur dioxide emissions from stationary sources.
7 or 7E	Nitrogen oxide emissions from stationary sources.
8 (modified)	Sulfuric acid mist. **
9	Visible emission determination of opacity. - At least three one hour runs to be conducted simultaneously with particulate testing. - At least one truck unloading into the mercury reactant storage silo (from start to finish).
10	Carbon monoxide emissions from stationary sources.
12	Determination of inorganic lead emissions from stationary sources.
13A or 13B	Fluoride emissions from stationary sources.
18 or 25	Volatile organic compounds concentration.
101A	Determination of particulate and gaseous mercury emissions.
104	Determination of beryllium emissions from stationary sources.
108	Determination of particulate and gaseous arsenic emissions.
EMTIC Test Method CTM-012.WPF	Chromium and copper emissions.

* Other approved EPA test methods may be substituted for the listed method unless the Department has adopted a specific test method for the air pollutant.

** Test for sulfuric acid mist only required when coal or tire derived fuel blends are burned at the facility.

A copy of this permit modification shall be filed with the referenced permit and shall become part of the permit. Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT MODIFICATION (including the FINAL permit Modification) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on ______________ to the person(s) listed:

Mr. Carlos Rionda, Osceola Power L.P. *
Mr. David Buff, Golder Associates
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. David Knowles, SD
Mr. J. Koerner, PBCPHU

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

_________________________ ____________
(Clerk) (Date)

Cogeneration Facility
Osceola Power L.P.
PSD-FL-197C and 0990331-006-AC
Pahokee, Palm Beach County

DRAFT

BACKGROUND

The applicant, Osceola Power L.P., constructed and began operating a 74 megawatt cogeneration facility in 1995. The facility consists of two identical spreader stoker boilers and associated equipment. The facility is permitted to burn primarily biomass (woodwaste and bagasse), with No. 2 fuel oil and coal used as supplemental fuels. Emission control equipment consists of an electrostatic precipitator (ESP) for particulate and heavy metals control, a selective non-catalytic reduction (SNCR) system for nitrogen oxides (NO_X)control, and an activated carbon injection system for mercury (Hg) control.

Ultimately the facility will provide the steam presently provided by the existing boilers at the adjacent Osceola Farms sugar mill. The boilers at that mill are scheduled for permanent shutdown by January 1, 1999.

A Best Available Control Technology (BACT) determination for NO_X control was not required at the time the permit was issued for the new boilers because potential emissions were estimated to be less than recent actual emissions from the boilers destined for shutdown. Very low NO_X emissions limits were set to avoid triggering New Source review for this pollutant. Osceola Power L.P. has met these limits but has encountered problems which may have been exacerbated by injection of excessive urea when trying to meet those limits. Among the problems are: relatively high plume opacity aggravated by formation of ammonium particulate species; increased deterioration of superheater tubes; and lower ESP particulate collection efficiency.

Osceola Power is requesting that the NO_X limits for the facility be relaxed. This results in a Significant Emission Increase (greater than 40 tons per year) in a PSD criteria pollutant at a Major Facility per Table 62-212.400-2. Relaxation of these limits will subject the facility to the PSD regulations, which requires a BACT determination pursuant to Rule 62-212.410, F.A.C. A project description, process description, and rule applicability are included in the Technical Evaluation and Preliminary Determination.

Following is the BACT determination proposed by the applicant:

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	PRESENT PERMITTED LIMIT lb/MMBtu heat input	PROPOSED BACT LIMIT lb/MMBtu heat input
Nitrogen Oxides:		
Biomass	0.12	0.15 lb/MMBtu
No. 2 Fuel Oil	0.12	0.15 lb/MMBtu
Coal	0.15	0.17 lb/MMBtu

The proposed increase in the emissions limits will result in an annual increase of approximately 150 tons per year (TPY) of NO_X. Osceola Power L.P. proposes to use the existing SNCR system to achieve the revised limits. The revised limits will be met by decreasing the ratio of urea injected into the furnace to NO_X present in the combustion gases. The applicant expects an amelioration of the present problems as a result of lowering use of urea.

DRAFT

DATE OF RECEIPT OF A BACT APPLICATION:

August 7, 1997

REVIEW GROUP MEMBERS:

A. A. Linero, New Source Review Section.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from this facility can be grouped into categories based upon the control equipment and techniques that are available to control emissions from these emission units. Using this approach, the emissions can be classified as follows:

- **Combustion Products** (e.g., SO_2, NO_X, PM). Controlled generally by good combustion of clean fuels or removal in add-on control equipment.
- **Products of Incomplete Combustion** (e.g., CO, VOC). Control is largely achieved by proper combustion techniques.

- **Other fuel contaminants** (fluorides, lead, mercury)

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Control of "non-regulated" air pollutants is considered in determining a BACT limit on a "regulated" pollutant (i.e., PM, SO_2, H_2SO_4, fluorides, etc.) if a reduction in "non-regulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

DRAFT

BACT POLLUTANT ANALYSIS

NITROGEN OXIDES (NO_X)

Oxides of nitrogen (NO_X) are generated during fuel combustion by oxidation of chemically bound nitrogen in the fuel (fuel NO_X) and by thermal fixation of nitrogen in the combustion air (thermal NO_X). As flame temperature increases, the amount of thermally generated NO_X increases. Fuel type affects the quantity and type of NO_X generated. Generally, biomass is low in nitrogen. Due to lower heating value and higher moisture, biomass causes lower flame temperatures and generates less thermal NO_X than oil or coal, which have higher fuel nitrogen content, and exhibit higher flame temperatures.

A review of EPA BACT/LAER Clearinghouse (BACT Clearinghouse) information indicates that NO_X emissions at many facilities burning primarily biomass are minimized by process control and good combustion practices, while several facilities employ the add-on technology of SNCR.

The applicant has proposed SNCR for control of NO_X emissions. SNCR involves the injection of either aqueous ammonia or urea into the boiler. The Osceola Power facility currently uses the NO_X OUT process whereby a urea-based reagent is injected into the flue gas. The urea selectively reduces the NO_X to nitrogen, carbon dioxide, and water. Generally, some unreacted urea in the flue gas results in emissions of ammonia (termed ammonia slip).

The applicant's proposed technology of SNCR is compared below with previous determinations documented by the BACT Clearinghouse.

BACT Clearinghouse Determinations

Determination:	Least Stringent	Most Stringent	Applicant Proposal
Year	1995	1992	1997
Limit (lb/MMBtu):	0.30	0.15	0.15

Based on information contained in the BACT/RACT/LAER Clearinghouse EPA database, all BACT determinations issued within the past 5 years for NO_X emissions from wood-fired boilers were reviewed. Most determinations were based on SNCR technology. A few determinations have been based on combustion control and boiler design and operation. Of the BACT determinations requiring SNCR, only a few have NO_X limits of less than 0.15 lb/MMBtu. A discussion of each of these is provided below:

- Multitrade LP - 0.1 lb/MMBtu; is a peaking boiler, not base load unit, and therefore is not directly comparable to Osceola.

- SAI Energy - 0.023 lb/MMBtu; is a fluidized bed unit, therefore not directly comparable to Osceola; also, was never constructed.
- Scott Paper - 43 ppm - Limit could not be met by Scott Paper; plan on raising to 86 ppm (similar to 0.15 lb/MMBtu).

BACT DETERMINATION RATIONALE:

According to the applicant and information from the BACT/LAER Clearinghouse, the range of NO_X BACT emission limits from recently-built wood-fired-boilers is 0.15 to 0.3 lb/MMBtu. This is consistent with determinations made by the Department for AES/Seminole Kraft and Wheelabrator Ridge of 0.29 and 0.14 lb/MMbtu respectively. Osceola Power has actually demonstrated that it can meet a limit of 0.12 lb/MMBtu while burning wood waste and bagasse, but has experienced operational problems including increased superheater tube failures, lower particulate removal efficiency, higher plume opacity, and disproportionately high ammonia emissions (slip). Ammonia is not a regulated air pollutant, but adds to the nitrogen load to the environment.

Identical units at Okeelanta Power are limited to 0.15 lb/MMBtu but experience less problems than those at Osceola Power. The most obvious difference in the operation at Osceola and Okeelanta is the amount of urea injected to accomplish NO_X removal.

Based on comparisons between Osceola and Okeelanta, the applicant has estimated the marginal cost of NO_X removal between 0.12 and 0.15 lb/MMBtu to be $25,600/ton. However the Department does not include costs related to lost production. Recalculation results in an estimate of approximately $13,000/ton which appears to be well in excess of typical cost effectiveness criteria used by the Department.

The limit previously established at Osceola when burning coal is 0.15 lb/MMBtu. The company has requested that this limit be raised to 0.17 lb/MMbtu, which is equal to that at Okeelanta.. The use of coal is limited to 4.4 percent of fuel use and neither Osceola nor Okeelanta has yet established any history of NO_X emissions or operational problems when firing or co-firing coal. At present there is no established limit for NO_X emissions when firing or co-firing tire-derived fuel (TDF). The applicant requested a limit when firing TDF of 0.17 lb/MMBtu.

The determination at Wheelabrator of 0.14 lb/MMBtu was made for the case when a fuel blend of 40 percent tires and 60 percent wood was fired. It is noted that Osceola Power agreed initially to a lower limit of 0.12 lb/MMBtu to avoid increases in NO_X emissions compared to the operation of certain existing boilers at Osceola Farms which are destined for permanent shutdown. This allowed the project to avoid being subjected to Non-Attainment Area New Source Review (NAANSR) and implementation of the Lowest Achievable Emissions Rate (LAER) irrespective of cost.

The area has since been redesignated as a maintenance area with respect to ozone. Therefore projects involving the ozone pre-cursors, VOCs and NO_X can be reviewed in accordance with PSD/BACT procedures instead of NAANSR/LAER procedures. The Department is reluctant to relax limits which were set to either comply with or "net out" of NAANSR. However, it appears that the impacts on ambient NO_X and ozone concentrations are negligible in this case. The energy, economic, and environmental impacts of the control method are apparently exacerbated by operating at the extreme limits of NO_X removal.

Selective Catalytic Reduction (SCR) may be a feasible control option for this type of unit. The technology is similar to SNCR, but involves injection of ammonia at a much lower temperature downstream of the furnace and in the presence of a catalyst, such as vanadium pentoxide. SCR has been demonstrated at coal-fired plants and could resolve concerns about the superheater tubes. However it would be costly and could add more factors to the problems experienced at the facility. The Department did not find any examples of SCR application to units fired primarily with woodwaste.

The air dispersion modeling analysis and the additional impact analysis presented by the applicant demonstrates that the increase in NO_X emissions will have insignificant effect upon ambient air concentrations in the area, and no adverse impact is predicted upon soils, vegetation or visibility in the area. Locally, there will be some improvement in visibility because of the reduction in ammonia salt emissions. Lower ammonia and ammonia salt emissions reduces the nitrogen load into the environment.

The maximum predicted annual average NO_X impact due to the proposed modification is 0.10 $\mu g/m^3$. The maximum impact upon the Everglades National Park PSD Class I area is 0.0013 $\mu g/m^3$, annual average. These impacts are well below specified significant impact levels of 1.0 $\mu g/m^3$ for the facility area, and 0.025 $\mu g/m^3$ for the Class I area.

BACT DETERMINATION BY DEP:

In consideration of all the facts and previous BACT determinations by the Department, the BACT determination for this proposed project is as follows:

A limit of 0.14 lb NO_X/MMBtu when firing wood waste, bagasse, or oil will be set. The justification is that it is equal to the most stringent demonstrated limit at a similar facility burning similar fuel. Although the cost effectiveness appears high, the Department believes that eventually optimization of operational and maintenance practices may reduce the problems and costs attributed to the control method without necessarily requiring further reductions in NO_X emission limits.

A BACT determination will not be set at this time for coal or TDF. This will be done when these fuels are burned or tested in the future. This will allow time for correction of the problems so that the effect of the control method can be separated from other practices at the facility. An example is the relocation of induced draft fans from upstream of the ESP to downstream of the ESP. In this case, the particulate control technique actually helped to remedy the problem of premature deterioration of the fans.

NO_X DETERMINATION

The BACT emission levels established by the Department are as follows:

POLLUTANT	PRESENT PERMITTED LIMIT lb/MMBtu heat input	DEPARTMENT BACT LIMIT lb/MMBtu heat input
Nitrogen Oxides:		
Biomass	0.12	0.14 lb/MMBtu
No. 2 Fuel Oil	0.12	0.14 lb/MMBtu
Coal	0.15	n/a
Tire-Derived Fuel	n/a	n/a

COMPLIANCE

Compliance for NO_X will be determined by annual stack tests utilizing EPA Method 7 or 7E, and by the continuous NO_X monitors installed on each boiler. Compliance with the limit of 0.14 lb/MMBtu shall be on a 30-day rolling average.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E., Administrator, New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

DRAFT

Recommended By:

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

Date:

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

P.E. Certification Statement

Permittee:

DEP File No. 0990331-006-AC (PSD-FL-197C)

Osceola Power L.P.
Cogeneration Facility
Pahokee, Palm Beach County

Project type:

Modification of Air Construction Permit for 74 Megawatt cogeneration facility. BACT determination for nitrogen oxides emissions increase of 100 TPY while firing bagasse and woodwaste. Revision of other emission limits below PSD-significance levels.

I HEREBY CERTIFY that the engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).

AA Linero 9/18

A.A. Linero, P.E. Date
Registration Number: 26032

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Phone (850) 488-1344
Fax (850) 922-6979

A. A. LINERO
CERTIFICATE
aal NO. 26032 9/18
STATE OF
FLORIDA
REGISTERED ENGINEER

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy

FROM: A. A. Linero *AA Linero 9/8*

DATE: September 8, 1997

SUBJECT: Osceola Power L.P. Cogeneration Facility
NO_X PSD/BACT Determination

Attached is the public notice package for modification of Osceola Power's permit to account for various revisions in pollutant emission rates. Only the revisions of the lead and NO_X limits result in increases in allowable annual emissions. Some adjustments were foreseen when the units were originally permitted. Specific Conditions 23 and 24 recognize that likelihood.

Osceola Power requested relaxation of its permitted NO_X limit from 0.12 to 0.15 lb/MMBtu while burning biomass and oil. Our most recent BACT determination for a similar facility was 0.14 lb/MMBtu for Wheelabrator Ridge in Auburndale using a similar Selective Non-Catalytic Reduction system. This value was selected as BACT for Osceola and they have concurred with our determination. NO_X emissions will increase by 100 TPY as a result of this modification. We are deferring any changes in NO_X BACT emissions limits when firing coal or TDF until these fuels are actually fired or tested.

Osceola Power believes the relaxation of the NO_X limit will help ameliorate problems they associate with excess use of urea. These include accelerated deterioration of superheater tubes, lower ESP particulate collection efficiency, and formation of particulate ammonium species which contribute to relatively high opacity. The lower urea use will also reduce the ammonia slip and nitrogen load to the environment.

I recommend you approval of this Intent to Issue.

Attachments

AAL/aal

Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

August 13, 1997

Mr. Jeff Koerner
Palm Beach Co. Health Department
901 Evernia Street
West Palm Beach, FL 33402

Re: Osceola Power Limited Partnership
Application for Revision of Air Permit

Dear Mr. Koerner:

At the request of Mr. Al Linero of the Florida Department of Environmental Protection (FDEP), I am enclosing a copy of the application for an air construction permit for the Osceola Power Limited Partnership (Osceola) cogeneration facility. The application requests revisions to certain emission limits now contained in the facility's air construction permit. The application was submitted to the FDEP at a meeting held in Tallahassee on August 7, 1997.

Please call if you have any questions concerning this application.

Sincerely,

David A. Buff

David A. Buff, P.E.
Principal Engineer

DB/arz

cc: James Meriwether
Al Linero
File (2)

9737510Y/F3/3

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

August 11, 1997

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS-Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

Re: Osceola Power, L.P. Cogeneration Facility
AIRS I.D. 0990331-006-AC, PSD-FL-242

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the above mentioned facility. The company is requesting a revision of certain emission limits now imposed on the cogeneration facility boilers. They have a nitrogen oxide limit of 0.12 pounds per million Btu achieved by Selective Non-Catalytic Reduction (SNCR). This limit was to avoid New Source Review. Because of operational problems and high opacity related to excessive use of urea, they wish to revise the limit and subject the project to a Best Available Control Technology (BACT) determination. Please forward your comments to my attention at the letterhead address. The Bureau's Fax number is (904)922-6979.

If you have any questions, please contact Willard Hanks at (904)488-1344.

Sincerely,

A. A. Linero 8/11

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/kt

Enclosures

cc: W. Hanks, BAR

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

August 11, 1997

Mr. Brian Beals, Section Chief
Air & Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA- Region IV
100 Alabama Street, SW
Atlanta, Georgia 30303

Re: Osceola Power, L.P. Cogeneration Facility
AIRS I.D. 0990331-006-AC, PSD-FL-242

Dear Mr. Beals:

Enclosed for your review and comment is an application for the above mentioned facility. The company is requesting a revision of certain emission limits now imposed on the cogeneration facility boilers. They have a nitrogen oxide limit of 0.12 pounds per million Btu achieved by Selective Non-Catalytic Reduction (SNCR). This limit was to avoid New Source Review. Because of operational problems and high opacity related to excessive use of urea, they wish to revise the limit and subject the project to a Best Available Control Technology (BACT) determination. Please forward your comments to my attention at the letterhead address. The Bureau's Fax number is (904)922-6979.

If you have any questions, please contact Willard Hanks at (904)488-1344.

Sincerely,

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/kt

Enclosures

cc: W. Hanks, BAR

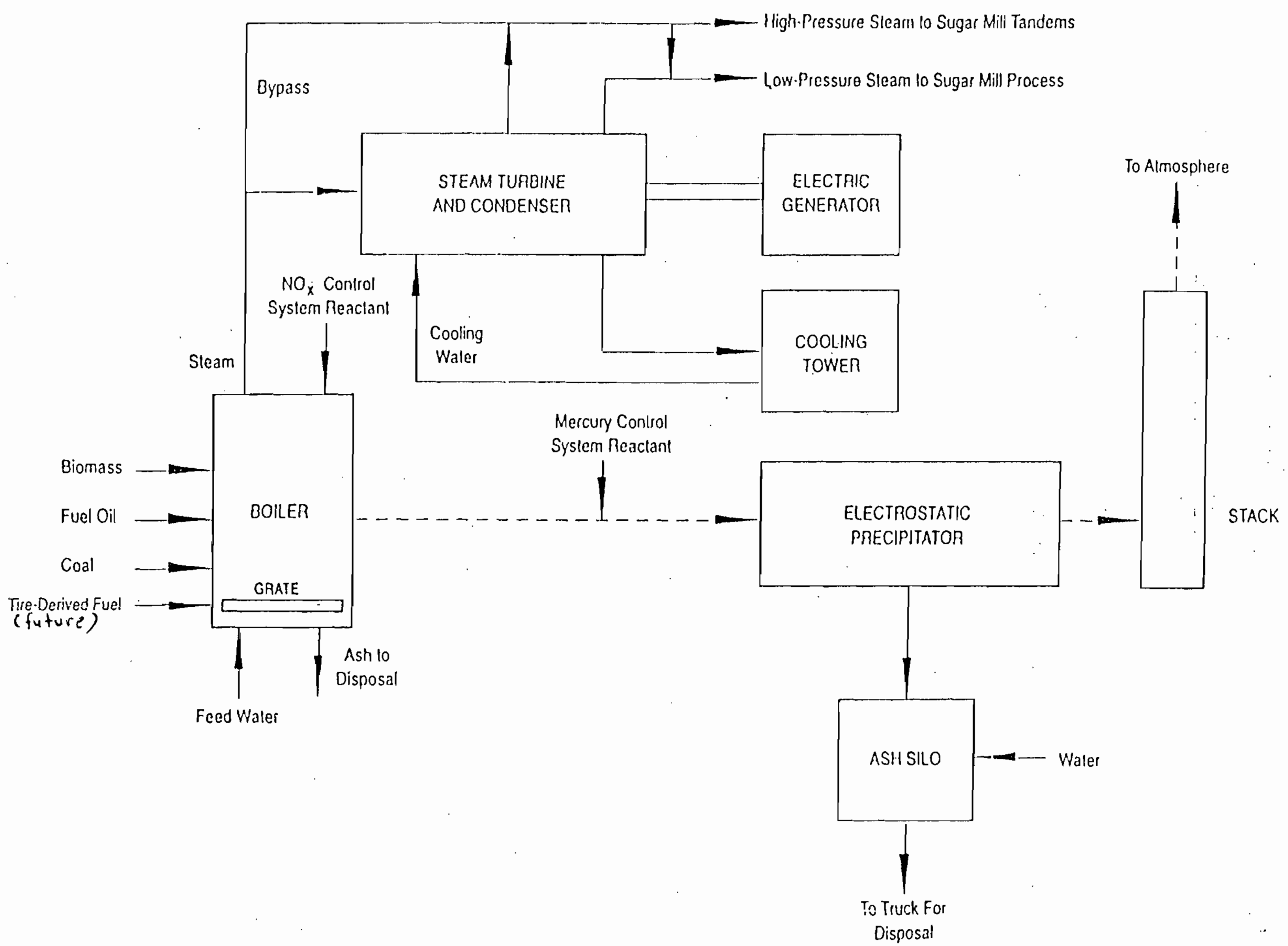

Figure 1
Simplified Flow Diagram for Osceola Power Cogeneration Facility

Golder Associates

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

August 6, 1997

RECEIVED

AUG 07 1997

BUREAU OF
AIR REGULATION

Mr. Clair Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Osceola Power Limited Partnership (Osceola) Cogeneration Facility
Permit AC50-269980; PSD-FL-197A

0990331-006-AC
PSD-FI-242

Dear Mr. Fancy:

Osceola Power is hereby submitting a permit application to request the revision of certain emission limits now imposed on the Osceola cogeneration facility boilers. The request is for the revision of biomass emission limits for lead, mercury, SO_2, and NO_x. In addition, a change in the averaging time for CO emissions from biomass fuels is requested, as well as revisions to the CO emissions limit for fossil fuels. The basis for these requested changes is described in the permit application and attachments.

Attached also is the permit application fee of $7,500. Please call or write with any questions you may have concerning this application.

Sincerely,

David A. Buff

David A. Buff, P.E.
Principal Engineer

DB/arz

cc: James Meriwether
File (2)

9737510Y/F3/WP/2

If IMAGESAFE logo in light gray tone is not present on back of document - Do not cash.

GATOR GENERATING COMPANY LIMITED PARTNERSHIP
DEBTOR IN POSSESSION CASE #97-32338
316 ROYAL POINCIANA PLAZA
PALM BEACH, FL 33480

149

June 20 19 97

[redacted]

PAY TO THE ORDER OF Florida Department of Environmental Protection $ 7,500.00

Seven thousand five hundred and no/100 ------------------------------------ DOLLARS

FIRST UNION
First Union National Bank of Florida
Belle Glade, Florida
24 Hour Information Service
1-800-735-1012

Suzanne Kingell

FOR Air permit mod.

FDE01 [redacted]

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

August 6, 1997

Mr. Clair Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Osceola Power Limited Partnership (Osceola) Cogeneration Facility
Permit AC50-269980; PSD-FL-197A

Dear Mr. Fancy:

Osceola Power is hereby submitting a permit application to request the revision of certain emission limits now imposed on the Osceola cogeneration facility boilers. The request is for the revision of biomass emission limits for lead, mercury, SO_2, and NO_x. In addition, a change in the averaging time for CO emissions from biomass fuels is requested, as well as revisions to the CO emissions limit for fossil fuels. The basis for these requested changes is described in the permit application and attachments.

Attached also is the permit application fee of $7,500. Please call or write with any questions you may have concerning this application.

Sincerely,

David A. Buff

David A. Buff, P.E.
Principal Engineer

DB/arz

cc: James Meriwether
File (2)

973751OY/F3/WP/2

OSCEOLA POWER
LIMITED PARTNERSHIP

APPLICATION FOR AIR PERMIT

AUGUST 1997

Prepared For:

Osceola Power Limited Partnership
U.S. 98 and Hatton Highway
Pahokee, Florida 33476

Prepared By:

Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

9737510Y/F3

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PART A

APPLICATION FOR AIR PERMIT

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

This section of the Application for Air Permit form identifies the facility and provides general information on the scope and purpose of this application. This section also includes information on the owner or authorized representative of the facility (or the responsible official in the case of a Title V source) and the necessary statements for the applicant and professional engineer, where required, to sign and date for formal submittal of the Application for Air Permit to the Department. If the application form is submitted to the Department using ELSA, this section of the Application for Air Permit must also be submitted in hard-copy.

Identification of Facility Addressed in This Application

Enter the name of the corporation, business, governmental entity, or individual that has ownership or control of the facility; the facility site name, if any; and the facility's physical location. If known, also enter the facility identification number.

1. Facility Owner/Company Name: **Osceola Power Limited Partnership**	
2. Site Name: **Osceola Power L.P.**	
3. Facility Identification Number: **0990331** [ ] Unknown	
4. Facility Location Information: Street Address or Other Locator: **U.S. 98 and Hatton Highway** City: **Pahokee** County: **Palm Beach** Zip Code: **33476**	
5. Relocatable Facility? [ ] Yes [x] No	6. Existing Permitted Facility? [x] Yes [ ] No

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	August 7, 1997
2. Permit Number:	0990331-006-AC
3. PSD Number (if applicable):	PSD-FL-242
4. Siting Number (if applicable):	

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official: Carlos Rionda, General Manager
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: Osceola Power Limited Partnership Street Address: P.O. Box 679 City: Pahokee State: FL Zip Code: 33476
3. Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (561) 924-7156 Fax: (561) 924-7428
4. Owner/Authorized Representative or Responsible Official Statement: I, the undersigned, am the owner or authorized representative* of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit. CRionda 8/4/97 Signature Date

* Attach letter of authorization if not currently on file.

Scope of Application

This Application for Air Permit addresses the following emissions unit(s) at the facility. An Emissions Unit Information Section (a Section III of the form) must be included for each emissions unit listed.

Emissions Unit ID		Description of Emissions Unit	Permit Type
Unit #	Unit ID		
1R	001	Boiler No.1 fired by Biomass/No.2 oil/Coal/TDF	AC1A
2R	002	Boiler No.2 fired by Biomass/No.2 oil/Coal/TDF	AC1A

See individual Emissions Unit (EU) sections for more detailed descriptions.
Multiple EU IDs indicated with an asterisk (*). Regulated EU indicated with an "R".

Purpose of Application and Category

Check one (except as otherwise indicated):

Category I: All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: __________

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed: __________

[ ] Air operation permit revision for a Title V source to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: __________

Operation permit to be renewed: __________

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. Also check Category III.

Operation permit to be revised/corrected: __________

[ ] Air operation permit revision for a Title V source for reasons other than construction or modification of an emissions unit. Give reason for the revision e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit to be revised: __________

Reason for revision: __________

Category II: All Air Construction Permit Applications Subject to Processing Under Rule 62-210.300(2)(b),F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s): ____________________

[ ] Renewal air operation permit under Rule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed: ____________________

[ ] Air operation permit revision for a synthetic non-Title V source. Give reason for revision; e.g.; to address one or more newly constructed or modified emissions units.

Operation permit to be revised: ____________________

Reason for revision: ____________________

Category III: All Air Construction Permit Applications for All Facilities and Emissions Units.

This Application for Air Permit is submitted to obtain:

[x] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any:
AC 50-269980; PSD-FL-197A

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

Current operation permit number(s): ____________________

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Application Processing Fee

Check one:

[x] Attached - Amount: $ **$ 7,500.00** [ ] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations: **This PSD application proposes revisions to the current construction permit for the 74 MW biomass fired cogeneration facility. This application requests revised permit limits for SO2, Pb, and Hg when burning woodwaste. In addition, the averaging time associated with the CO emissions limit is being requested to be changed to a 24-hour average, and the NOx emissions limit is being revised. These revisions are based on actual stack test data and fuel quality of biomass fuel.**
2. Projected or Actual Date of Commencement of Construction : **1 Jul 1997**
3. Projected Date of Completion of Construction : **31 Dec 1998**

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2. Professional Engineer Mailing Address: Organization/Firm: **Golder Associates Inc.** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3. Professional Engineer Telephone Numbers: Telephone: **(352) 336-5600** Fax: **(352) 336-6603**

4. Professional Engineer's Statement:

I, the undersigned, hereby certify, except as particularly noted herein*, that:

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ] if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [X] if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff — 8/7/97

Signature (seal) — Date

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact: **David A. Buff, P.E.**
2. Application Contact Mailing Address: Organization/Firm: **Golder Associates Inc.** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3. Application Contact Telephone Numbers: Telephone: **(352) 336-5600** Fax: **(352) 336-6603**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates:
   Zone: 17 East (km): 544.2 North (km): 2968.0

2. Facility Latitude/Longitude:
   Latitude (DD/MM/SS): 26 / 49 / 45 Longitude: (DD/MM/SS): 80 / 33 / 0

3. Governmental Facility Code:	4. Facility Status Code:	5. Facility Major Group SIC Code:	6. Facility SIC(s):
0	A	49	4911

7. Facility Comment (limit to 500 characters):
   74 MW Electric Cogen using biomass, oil, coal, or tire-derived fuel.

Facility Contact

1. Name and Title of Facility Contact:
   Carlos Rionda, General Manager

2. Facility Contact Mailing Address:
   Organization/Firm: Osceola Power Limited Partnership
   Street Address: P.O. Box 679
   City: Pahokee State: FL Zip Code: 33476

3. Facility Contact Telephone Numbers:
   Telephone: (561) 924-7156 Fax: (561) 924-7428

Facility Regulatory Classifications

1. Small Business Stationary Source? [ ] Yes [x] No [ ] Unknown
2. Title V Source? [x] Yes [ ] No
3. Synthetic Non-Title V Source? [ ] Yes, [x] No
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)? [x] Yes [ ] No
5. Synthetic Minor Source of Pollutants Other than HAPs? [ ] Yes [x] No
6. Major Source of Hazardous Air Pollutants (HAPs)? [x] Yes [ ] No
7. Synthetic Minor Source of HAPs? [ ] Yes [x] No
8. One or More Emissions Units Subject to NSPS? [x] Yes [ ] No
9. One or More Emissions Units Subject to NESHAP? [ ] Yes [x] No
10. Title V Source by EPA Designation? [ ] Yes [x] No
11. Facility Regulatory Classifications Comment (limit to 200 characters):

B. FACILITY REGULATIONS

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

Not Applicable

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

62-210.300 - Permits Required **62-212.400 - Prevention of Significant Deterioration**

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted		2. Pollutant Classification
PM	Particulate Matter - Total	A
PM10	Particulate Matter - PM10	A
SO2	Sulfur Dioxide	A
NOx	Nitrogen Oxides	A
CO	Carbon Monoxide	A
VOC	Volatile Organic Compounds	A
PB	Lead - Total	B
H114	Mercury Compounds	B
H021	Beryllium Compounds	B
FL	Fluorides - Total	B
SAM	Sulfuric Acid Mist	B
HAPS	Total Hazardous Air Pollutants	A
H106	Hydrochloric acid	A

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Detail Information:

1. Pollutant Emitted:		
2. Requested Emissions Cap:	(lb/hr)	(tons/yr)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters):		

Facility Pollutant Detail Information:

1. Pollutant Emitted:		
2. Requested Emissions Cap:	(lb/hr)	(tons/yr)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters):		

E. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location:
   [x] Attached, Document ID: PART B
   [ ] Not Applicable [ ] Waiver Requested

2. Facility Plot Plan:
   [x] Attached, Document ID: PART B
   [ ] Not Applicable [ ] Waiver Requested

3. Process Flow Diagram(s):
   [x] Attached, Document ID(s): PART B
   [ ] Not Applicable [ ] Waiver Requested

4. Precautions to Prevent Emissions of Unconfined Particulate Matter:
   [x] Attached, Document ID: PART B
   [ ] Not Applicable [ ] Waiver Requested

5. Fugitive Emissions Identification:
   [x] Attached, Document ID: PART B
   [ ] Not Applicable [ ] Waiver Requested

6. Supplemental Information for Construction Permit Application:
   [x] Attached, Document ID: PART B
   [ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt Activities:
   [ ] Attached, Document ID: ____
   [x] Not Applicable

8. List of Equipment/Activities Regulated under Title VI:
   [ ] Attached, Document ID: ____
   [ ] Equipment/Activities On site but Not Required to be Individually Listed
   [x] Not Applicable

9. Alternative Methods of Operation:
   [ ] Attached, Document ID: ____
   [x] Not Applicable

10. Alternative Modes of Operation (Emissions Trading):
    [ ] Attached, Document ID: ____
    [x] Not Applicable

11. Identification of Additional Applicable Requirements: [ ] Attached, Document ID: ____________ [x] Not Applicable
12. Compliance Assurance Monitoring Plan: [ ] Attached, Document ID: ____________ [x] Not Applicable
13. Risk Management Plan Verification: [ ] Plan Submitted to Implementing Agency - Verification Attached Document ID: ____________ [ ] Plan to be Submitted to Implementing Agency by Required Date [x] Not Applicable
14. Compliance Report and Plan [ ] Attached, Document ID: ____________ [x] Not Applicable
15. Compliance Statement (Hard-copy Required) [ ] Attached, Document ID: ____________ [x] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

<u>**Type of Emissions Unit Addressed in This Section**</u>

1. Regulated or Unregulated Emissions Unit? Check one:

[x] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one:

[x] This Emissions Unit information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
   Boiler No.1 fired by Biomass/No.2 oil/Coal/TDF

2. Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown
   001

3. Emissions Unit Status Code: **A**	4. Acid Rain Unit? [ ] Yes [x] No	5. Emissions Unit Major Group SIC Code: **49**

6. Emissions Unit Comment (limit to 500 characters):
   74 MW gross generating capacity for entire facility

Emissions Unit Control Equipment Information

A.

1. Description (limit to 200 characters):

   ESP - Electrostatic Precipitator

2. Control Device or Method Code: **10**

B.

1. Description (limit to 200 characters):

   Selective Non-Catalytic Reduction for NOx

2. Control Device or Method Code: **107**

C.

1. Description (limit to 200 characters):

   Activated Carbon injection system.

2. Control Device or Method Code: **48**

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date:	
2. Long-term Reserve Shutdown Date:	
3. Package Unit: Manufacturer:	Model Number:
4. Generator Nameplate Rating:	74 MW
5. Incinerator Information: Dwell Temperature:	°F
Dwell Time:	seconds
Incinerator Afterburner Temperature:	°F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	760	mmBtu/hr
2. Maximum Incineration Rate:	lbs/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:		
5. Operating Capacity Comment (limit to 200 characters): Maximum heat input rates: Biomass - 760 MMBtu/hr; No.2 Fuel Oil - 600 MMBtu/hr; Coal - 530 MMBtu/hr; Tire-derived fuel - 370 MMBtu/hr		

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:			
24	hours/day	7	days/week
52	weeks/yr	8,760	hours/yr

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Rule Applicability Analysis (Required for Category II Applications and Category III applications involving non Title-V sources. See Instructions.)

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

40 CFR 60,Subpart Da 40 CFR 60,Subparts Ea and Cb

E. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: BLR 1	
2. Emission Point Type Code: [x] 1 [ ] 2 [ ] 3 [ ] 4	
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [x] V [ ] W	
6. Stack Height:	225 feet
7. Exit Diameter:	10 feet
8. Exit Temperature:	295 °F

9. Actual Volumetric Flow Rate:	246,000 acfm
10. Percent Water Vapor:	%
11. Maximum Dry Standard Flow Rate:	dscfm
12. Nonstack Emission Point Height:	feet
13. Emission Point UTM Coordinates: Zone: 17 East (km): 544.2 North (km): 2968.0	
14. Emission Point Comment (limit to 200 characters): **Stack parameters based on biomass firing.**	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 1 of 5

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Electric Utility Boiler - Bagasse**	
2. Source Classification Code (SCC): **1-01-011-01**	
3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **89.412**	5. Maximum Annual Rate: **783,144**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.05**	8. Maximum Percent Ash: **0.4**
9. Million Btu per SCC Unit: **8**	
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit: 8.5. Total bagasse both boilers = 965,647 TPY**	

Segment Description and Rate: Segment 2 of 5

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): Electric Utility Boiler - Wood Fired Boiler	
2. Source Classification Code (SCC): 1-01-009-03	
3. SCC Units: Tons Burned	
4. Maximum Hourly Rate: 69.091	5. Maximum Annual Rate: 605,236
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: 0.11	8. Maximum Percent Ash: 3.2
9. Million Btu per SCC Unit: 11	
10. Segment Comment (limit to 200 characters): Total wood waste both boilers = 623,055 TPY	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 3 of 5

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Electric Utility Boiler - Distillate Oil - Grades 1 and 2 Oil**	
2. Source Classification Code (SCC): **1-01-005-01**	
3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **4.348**	5. Maximum Annual Rate: **13,942**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.05**	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **138**	
10. Segment Comment (limit to 200 characters): **Maximum Annual Rate: 13,942.251. Total No.2 Fuel Oil both boilers = 13,942,251 gal/yr. This represents 24.9% oil firing on a heat input basis.**	

Segment Description and Rate: Segment 4 of 5

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Electric Utility Boiler - Bituminous Coal - Spreader Stoker**	
2. Source Classification Code (SCC): **1-01-002-04**	
3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **22.084**	5. Maximum Annual Rate: **14,883**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.7**	8. Maximum Percent Ash: **3.7**
9. Million Btu per SCC Unit: **24**	
10. Segment Comment (limit to 200 characters): **Total coal both boilers = 14,883 TPY. This represents 5.44% coal burning on a heat input basis.**	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 5 of 5

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Electric Utility Boiler - Solid Waste - Tire Derived Fuel**	
2. Source Classification Code (SCC): **1-01-012-01**	
3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **11.94**	5. Maximum Annual Rate: **36,537**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **1.2**	8. Maximum Percent Ash: **4.9**
9. Million Btu per SCC Unit: **31**	
10. Segment Comment (limit to 200 characters): **Max hourly rate based on 370 MMBtu/hr TDF. Total TDF both boilers = 36,537 TPY. This represents 13.8% TDF burning on a heat input basis (5.4% on a weight basis).**	

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters):
2. Source Classification Code (SCC):
3. SCC Units:
4. Maximum Hourly Rate: / 5. Maximum Annual Rate:
6. Estimated Annual Activity Factor:
7. Maximum Percent Sulfur: / 8. Maximum Percent Ash:
9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
H114	048		EL
PB	010		EL
H021	010		EL
PM	010		EL
PM10	010		EL
SO2			EL
NOx	107		EL
CO			EL
VOC			EL
FL			EL
SAM			EL
HAPS			NS
H106			NS
H107			NS

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **H114**

2. Total Percent Efficiency of Control: **25** %

3. Potential Emissions: **0.0045** lb/hour **0.0168** tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor: **See Part B**

   Reference:

7. Emissions Method Code:

   [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

8. Calculation of Emissions (limit to 600 characters):

   See Part B

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   0.0168 TPY total both boilers

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 3.5 E-06 lb/MMBtu
4. Equivalent Allowable Emissions: 0.0027 lb/hour 0.0123 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 101A
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Emission limit is for bagasse. Emission limit for wood waste is 4.0E-06 lb/MMBtu.

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 2.4 E-06 lb/MMBtu
4. Equivalent Allowable Emissions: 0.0014 lb/hour 0.0019 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 101A
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on No.2 fuel oil firing.

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 8.4 E-06 lb/MMBtu
4. Equivalent Allowable Emissions: 0.0045 lb/hour 0.0015 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 101A
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on coal firing

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 6.5 E-06 lb/MMBtu
4. Equivalent Allowable Emissions: 0.0024 lb/hour 0.0037 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 101A
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on tire-derived fuel firing.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: PB
2. Total Percent Efficiency of Control: 98 %
3. Potential Emissions: 0.12 lb/hour 0.22 tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: See Part B Reference:
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): **See Part B**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **0.27 TPY total for both boilers**

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 2.7 E-06 lb/MMBtu	
4. Equivalent Allowable Emissions: 0.0021 lb/hour	0.22 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 12	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on bagasse firing. Limit for woodwaste is 1.6E-04 lb/MMBtu.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 8.9 E-07 lb/MMBtu	
4. Equivalent Allowable Emissions: 0.0005 lb/hour	0.0007 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 12	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on No.2 fuel oil firing.	

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 5.1 E-06 lb/MMBtu	
4. Equivalent Allowable Emissions: 0.0027 lb/hour	0.0009 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 12	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on coal firing.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 4.2 E-05 lb/MMBtu	
4. Equivalent Allowable Emissions: 0.0155 lb/hour	0.024 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 12	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on tire-derived fuel firing.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: H021

2. Total Percent Efficiency of Control: 98 %

3. Potential Emissions: 0.0031 lb/hour 0.0011 tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor: 5.9 E-06 lb/MMBtu

   Reference: See Part B

7. Emissions Method Code:

   [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   5.9E-06 lb/MMBtu x 530 MMBtu/hr = 0.0031 lb/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Based on coal firing. 0.0013 TPY total for both boilers.

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 3.5 E-07 lb/MMBtu
4. Equivalent Allowable Emissions: 0.0002 lb/hour 0.0003 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 104
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Equivalent Allowable Emissions = 0.00027 TPY. Based on No.2 fuel oil firing.

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 5.9 E-06 lb/MMBtu
4. Equivalent Allowable Emissions: 0.0031 lb/hour 0.0011 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 104
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on coal firing.

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 4.5 E-07 lb/MMBtu
4. Equivalent Allowable Emissions: 0.0002 lb/hour 0.0003 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 104
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Equivalent Allowable Emissions: 0.00017 lbs/hr; 0.00025 tons/yr. Based on tire-derived fuel firing.

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: PM			
2. Total Percent Efficiency of Control:	98 %		
3. Potential Emissions:	22.8 lb/hour	99.9 tons/year	
4. Synthetically Limited?	[x] Yes	[ ] No	
5. Range of Estimated Fugitive/Other Emissions:	[ ] 1 [ ] 2 [ ] 3	________ to ________ tons/yr	
6. Emission Factor: 0.03 lb/MMBtu	Reference: 40 CFR 60 Subpa Da		
7. Emissions Method Code:	[ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5		
8. Calculation of Emissions (limit to 600 characters):	0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):	123.12 TPY total for both boilers		

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: RULE	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.03 lb/MMBtu	
4. Equivalent Allowable Emissions: 22.8 lb/hour	99.9 tons/year
5. Method of Compliance (limit to 60 characters): Annual Stack testing using EPA Method 5.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): 40 CFR 60, Subpart Da. Maximum lb/hr based on biomass firing.	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lb/hour	tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **PM10**	
2. Total Percent Efficiency of Control:	**98** %
3. Potential Emissions: **22.8** lb/hour	**99.9** tons/year
4. Synthetically Limited? [x] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr	
6. Emission Factor: **0.03 lb/MMBtu** Reference: **40 CFR 60 Subpart Da**	
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5	
8. Calculation of Emissions (limit to 600 characters): **0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr**	
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **123.12 TPY total for both boilers**	

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: RULE	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.03 lb/MMBtu	
4. Equivalent Allowable Emissions: 22.8 lb/hour	99.9 tons/year
5. Method of Compliance (limit to 60 characters): Annual Stack Test using EPA Method 5.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): 40 CFR 60, Subpart Da. Maximum lb/hr based on biomass firing.	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lb/hour	tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SO_2

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 636 lb/hour 315 tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor: 1.2 lb/MMBtu

   Reference: 40 CFR 60 Subpart Da

7. Emissions Method Code:

   [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

8. Calculation of Emissions (limit to 600 characters):

   1.2 lb/MMBtu x 530 MMBtu/hr Coal = 636.0 lb/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   339.0 TPY total for both boilers

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: RULE	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 1.2 lb/MMBtu	
4. Equivalent Allowable Emissions: 636 lb/hour	315 tons/year
5. Method of Compliance (limit to 60 characters): Limit coal burning to 5.4% of heat input for entire facility	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): 40 CFR 60, Subpart Da. Based on coal firing	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.05 lb/MMBtu	
4. Equivalent Allowable Emissions: 30 lb/hour	39 tons/year
5. Method of Compliance (limit to 60 characters): Limit fuel oil burning to 24.9% for any single boiler	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on No.2 fuel oil firing and BACT.	

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: See Comment	
4. Equivalent Allowable Emissions: 76 lb/hour	106.5 tons/year
5. Method of Compliance (limit to 60 characters): Continuous SO2 monitor	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Requested Allowable Emissions and Units: 0.1 lb/MMBtu(24-hr avg); 0.02 lb/MMBtu(annual avg) for bagasse and 0.05 lb/MMBtu(annual avg) for wood. Emissions based on biomass firing & fuel sulfur content.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: See Comment	
4. Equivalent Allowable Emissions: 444 lb/hour	226.6 tons/year
5. Method of Compliance (limit to 60 characters): Continuous SO2 monitor.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Requested allowable emissions: 1.2 lb/MMBtu, 24-hr avg.; 0.4 lb/MMBtu, annual avg. Emissions based on tire-derived fuel firing.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: NOx
2. Total Percent Efficiency of Control: %
3. Potential Emissions: 121.4 lb/hour 510.7 tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr
6. Emission Factor: 0.15 lb/MMBtu Reference: Based on NOx control
7. Emissions Method Code: [x] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): Hourly: 0.15 lb/MMBtu x 390 MMBtu/hr Biomass = 58.5 lb/hr; 0.17 lb/MMBtu x 370 MMBtu/hr TDF = 62.9 lb/hr; Total = 58.5 + 62.9 = 121.4 lb/hr
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): 626.9 TPY total for both boilers

Emissions Unit Information Section 1 of 2
Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: ESCPSD	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.15 lb/MMBtu	
4. Equivalent Allowable Emissions: 114 lb/hour	499.4 tons/year
5. Method of Compliance (limit to 60 characters): Annual stack test using EPA Method 7 or 7E	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on biomass firing	

B.

1. Basis for Allowable Emissions Code: ESCPSD	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.15 lb/MMBtu	
4. Equivalent Allowable Emissions: 90 lb/hour	117.1 tons/year
5. Method of Compliance (limit to 60 characters): Limit fuel oil burning to 24.9% for any single boiler	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on No.2 fuel oil firing	

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **ESCPSD**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.17 lb/MMBtu**	
4. Equivalent Allowable Emissions: **90.1** lb/hour	**30.4** tons/year
5. Method of Compliance (limit to 60 characters): **Limit coal burning to 5.44% for any single boiler**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on coal firing**	

B.

1. Basis for Allowable Emissions Code: **ESCPSD**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.17 lb/MMBtu**	
4. Equivalent Allowable Emissions: **62.9** lb/hour	**96.3** tons/year
5. Method of Compliance (limit to 60 characters): **See Comment**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Method of Compliance: Annual stack testing using EPA Method 7 or 7E. Limit TDF Firing to 17% on an annual basis. Based on tire-derived fuel firing.**	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: CO
2. Total Percent Efficiency of Control: %
3. Potential Emissions: 266 lb/hour 1,165.1 tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr
6. Emission Factor: 0.35 lb/MMBtu Reference: Boiler design
7. Emissions Method Code: [x] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): **0.35 lb/MMBtu x 760 MMBtu/hr = 266 lb/hr**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **Hourly emissions represent 24-hour average. Total emissions both boilers = 1,436.4 TPY.**

Emissions Unit Information Section 1 of 2
Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.35 lb/MMBtu	
4. Equivalent Allowable Emissions: 266 lb/hour	1,165.1 tons/year
5. Method of Compliance (limit to 60 characters): Continuous CO monitor	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on biomass firing; limit is 24-hour average.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.35 lb/MMBtu	
4. Equivalent Allowable Emissions: 210 lb/hour	273.2 tons/year
5. Method of Compliance (limit to 60 characters): Limit fuel burning to 24.9% for any single boiler	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on No.2 fuel oil firing; limit is 24-hour average.	

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.35 lb/MMBtu	
4. Equivalent Allowable Emissions: 185.5 lb/hour	62.5 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 10 annually	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on coal firing. Limit coal burning to 4.4% entire facility; 5.44% for any single boiler; limit is 24-hr avg.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.35 lb/MMBtu	
4. Equivalent Allowable Emissions: 129.5 lb/hour	198.3 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 10 annually.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on tire-derived fuel firing. Limit is 24-hr avg. TDF limited to 25% for each boiler on hourly basis.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **VOC**
2. Total Percent Efficiency of Control: %
3. Potential Emissions: **45.6** lb/hour **173.1** tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: **0.06 lb/MMBtu** Reference: **Boiler design**
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): **0.06 lb/MMBtu x 760 MMBtu/hr = 45.6 lb/hr**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **Based on biomass firing**

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: ESCNAA
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.03 lb/MMBtu
4. Equivalent Allowable Emissions: 15.9 lb/hour 5.36 tons/year
5. Method of Compliance (limit to 60 characters): Limit coal burning to 5.44% for any single boiler
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on coal firing

B.

1. Basis for Allowable Emissions Code: ESCNAA
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.04 lb/MMBtu
4. Equivalent Allowable Emissions: 14.8 lb/hour 22.7 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 25 or 25A annually.
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on tire-derived fuel firing. TDF limited to 25% for any single boiler on hourly basis.

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: ESCNAA	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: See Comment	
4. Equivalent Allowable Emissions: 45.6 lb/hour	173.1 tons/year
5. Method of Compliance (limit to 60 characters): Annual stack test using EPA Method 25 or 25A	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on biomass firing. Requested Allowable Emissions and Units: 0.06 lb/MMBtu bagasse; 0.04 lb/MMBtu wood waste.	

B.

1. Basis for Allowable Emissions Code: ESCNAA	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.03 lb/MMBtu	
4. Equivalent Allowable Emissions: 18 lb/hour	23.4 tons/year
5. Method of Compliance (limit to 60 characters): Limit fuel burning to 24.9% for any single boiler	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on No.2 fuel oil firing	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: FL

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 12.7 lb/hour 4.29 tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ___________ to ___________ tons/yr

6. Emission Factor: 0.024 lb/MMBtu

   Reference: See Part B

7. Emissions Method Code:

   [x] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   0.024 lb/MMBtu x 530 MMBtu/hr = 12.7 lb/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Based on coal firing

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: See Comment	
4. Equivalent Allowable Emissions: 0.0038 lb/hour	0.005 tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Allowable emissions: 6.3E-06 lb/MMBtu. Based on No.2 fuel oil firing.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.024 lb/MMBtu	
4. Equivalent Allowable Emissions: 12.7 lb/hour	4.29 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 13A or 13B once every 5 years.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on coal firing.	

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **See Comment**	
4. Equivalent Allowable Emissions:	**0.24** lb/hour **0.37** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 13A or 13B once every 5 years.**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on tire-derived fuel firing**	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions:	lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SAM		
2. Total Percent Efficiency of Control:	%	
3. Potential Emissions:	5.6 lb/hour	4.83 tons/year
4. Synthetically Limited? [x] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr		
6. Emission Factor: 0.01 lb/MMBtu Reference: See Part B		
7. Emissions Method Code: [x] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5		
8. Calculation of Emissions (limit to 600 characters): 0.0049 lb/MMBtu x 390 MMBtu/hr = 1.91 lb/hr; 0.010 lb/MMBtu x 370 MMBtu/hr = 3.7 lb/hr. Total = 1.91 + 3.7 = 5.6 lb/hr		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): Based on biomass/TDF firing. Total both boilers = 6.0 TPY.		

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.01 lb/MMBtu	
4. Equivalent Allowable Emissions: 5.3 lb/hour	1.8 tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on coal firing	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.01 lb/MMBtu	
4. Equivalent Allowable Emissions: 3.7 lb/hour	1.93 tons/year
5. Method of Compliance (limit to 60 characters): Method 8 once every 5 years	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on tire derived fuel firing. Annual average based on 0.0066 lb/MMBtu.	

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.0049 lb/MMBtu,24-hr**
4. Equivalent Allowable Emissions: **3.72** lb/hour **3.26** tons/year
5. Method of Compliance (limit to 60 characters): **Method 8 once every 5 years**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on biomass firing. Annual average based on 0.00098 lb/MMBtu.**

B.

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.0025 lb/MMBtu**
4. Equivalent Allowable Emissions: **1.5** lb/hour **1.95** tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on No.2 fuel oil firing**

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitations: Visible Emissions Limitation 1 of 1

1.	Visible Emissions Subtype: VE20
2.	Basis for Allowable Opacity: [x] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: 20. % Exceptional Conditions: 27. % Maximum Period of Excess Opacity Allowed: 6 min/hour
4.	Method of Compliance: EPA Method 9
5.	Visible Emissions Comment (limit to 200 characters): 40 CFR 60 Subpart Da

Visible Emissions Limitations: Visible Emissions Limitation _____ of _____

1.	Visible Emissions Subtype:
2.	Basis for Allowable Opacity: [ ] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance:
5.	Visible Emissions Comment (limit to 200 characters):

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System Continuous Monitor 1 of 6

1. Parameter Code: VE	2. Pollutant(s):
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Durag Model Number: D-R281-31-AV	Serial Number: 31500
5. Installation Date: 05 Dec 1995	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): 40 CFR 60, Subpart Da	

Continuous Monitoring System Continuous Monitor 2 of 6

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Thermo Environmental Instruments Model Number: 42D	Serial Number: 42D-53361-296
5. Installation Date: 05 Dec 1995	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): 40 CFR 60, Subpart Da	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System Continuous Monitor 3 of 6

1. Parameter Code: EM	2. Pollutant(s): SO2
3. CMS Requirement: [ ] Rule [x] Other	
4. Monitor Information: Monitor Manufacturer: Thermo Environmental Instruments Model Number: 43B Serial Number: 43B-53359-296	
5. Installation Date: 05 Dec 1995	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): 40 CFR 60, Subpart Da	

Continuous Monitoring System Continuous Monitor 4 of 6

1. Parameter Code: EM	2. Pollutant(s): CO
3. CMS Requirement: [ ] Rule [X] Other	
4. Monitor Information: Monitor Manufacturer: Thermo Environmental Instruments Model Number: 48 Serial Number: 48-53434-296	
5. Installation Date: 05 Dec 1995	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters):	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System Continuous Monitor 5 of 6

1. Parameter Code: O2	2. Pollutant(s):
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Yokogowa Model Number: 2A8C	Serial Number: JJ113PA188
5. Installation Date: 05 Dec 1995	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): 40 CFR 60, Subpart Da	

Continuous Monitoring System Continuous Monitor 6 of 6

1. Parameter Code: CO2	2. Pollutant(s):
3. CMS Requirement: [ ] Rule [X] Other	
4. Monitor Information: Monitor Manufacturer: California Analytical Model Number: ZRH1	Serial Number: N5B3528T
5. Installation Date: 05 Dec 1995	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters):	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

[x] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[x] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3.	Increment Consuming/Expanding Code:			
	PM	[x] C	[ ] E	[ ] Unknown
	SO_2	[x] C	[ ] E	[ ] Unknown
	NO_2	[x] C	[ ] E	[ ] Unknown
4.	Baseline Emissions:			
	PM	lb/hour		tons/year
	SO_2	lb/hour		tons/year
	NO_2			tons/year
5.	PSD Comment (limit to 200 characters):			

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements for All Applications

1.	Process Flow Diagram [X] Attached, Document ID: PART B [ ] Not Applicable		[ ] Waiver Requested
2.	Fuel Analysis or Specification [X] Attached, Document ID: PART B [ ] Not Applicable		[ ] Waiver Requested
3.	Detailed Description of Control Equipment [X] Attached, Document ID: PART B [ ] Not Applicable		[ ] Waiver Requested
4.	Description of Stack Sampling Facilities [ ] Attached, Document ID: ____ [X] Not Applicable		[ ] Waiver Requested
5.	Compliance Test Report [ ] Attached, Document ID: ____ [ ] Previously Submitted, Date: ____		[X] Not Applicable
6.	Procedures for Startup and Shutdown [ ] Attached, Document ID: ____		[X] Not Applicable
7.	Operation and Maintenance Plan [ ] Attached, Document ID: ____		[X] Not Applicable
8.	Supplemental Information for Construction Permit Application [X] Attached, Document ID: PART B		[ ] Not Applicable
9.	Other Information Required by Rule or Statute [X] Attached, Document ID: PART B		[ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

10.	Alternative Methods of Operation [ ] Attached, Document ID: ____________ [ ] Not Applicable
11.	Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID: ____________ [ ] Not Applicable
12.	Identification of Additional Applicable Requirements [ ] Attached, Document ID: ____________ [ ] Not Applicable
13.	Compliance Assurance Monitoring Plan [ ] Attached, Document ID: ____________ [ ] Not Applicable
14.	Acid Rain Permit Application (Hard Copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: ____________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: ____________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: ____________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: ____________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one:

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one:

[X] This Emissions Unit information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): **Boiler No.2 fired by Biomass/No.2 oil/Coal/TDF**		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown **002**		
3. Emissions Unit Status Code: **A**	4. Acid Rain Unit? [ ] Yes [x] No	5. Emissions Unit Major Group SIC Code: **49**
6. Emissions Unit Comment (limit to 500 characters): **74 MW gross generating capacity for entire facility**		

Emissions Unit Control Equipment Information

A.

1. Description (limit to 200 characters): **ESP - Electrostatic Precipitator**	
2. Control Device or Method Code: **10**	

B.

1. Description (limit to 200 characters): **Selective Non-Catalytic Reduction for NOx**	
2. Control Device or Method Code: **107**	

C.

1. Description (limit to 200 characters): **Activated Carbon injection system.**	
2. Control Device or Method Code: **48**	

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date:	
2. Long-term Reserve Shutdown Date:	
3. Package Unit: Manufacturer:	Model Number:
4. Generator Nameplate Rating:	74 MW
5. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	760	mmBtu/hr
2. Maximum Incineration Rate:	lbs/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:		
5. Operating Capacity Comment (limit to 200 characters): **Maximum heat input rates: Biomass - 760 MMBtu/hr; No.2 Fuel Oil - 600 MMBtu/hr; Coal - 530 MMBtu/hr; Tire-derived fuel - 370 MMBtu/hr**		

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:			
24	hours/day	7	days/week
52	weeks/yr	8,760	hours/yr

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Rule Applicability Analysis (Required for Category II Applications and Category III applications involving non Title-V sources. See Instructions.)

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

40 CFR 60, Subpart Da 40 CFR 60, Subparts Ea and Cb

E. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: BLR 2		
2. Emission Point Type Code: [x] 1 [ ] 2 [ ] 3 [ ] 4		
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [x] V [ ] W		
6. Stack Height:	225	feet
7. Exit Diameter:	10	feet
8. Exit Temperature:	295	°F

9. Actual Volumetric Flow Rate:	246,000 acfm	
10. Percent Water Vapor:	%	
11. Maximum Dry Standard Flow Rate:	dscfm	
12. Nonstack Emission Point Height:	feet	
13. Emission Point UTM Coordinates: Zone: 17	East (km): 544.2	North (km): 2968.0
14. Emission Point Comment (limit to 200 characters): Stack parameters based on biomass firing.		

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 1 of 5

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Electric Utility Boiler - Bagasse**	
2. Source Classification Code (SCC): **1-01-011-01**	
3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **89.412**	5. Maximum Annual Rate: **783,144**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.05**	8. Maximum Percent Ash: **0.4**
9. Million Btu per SCC Unit: **8**	
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit: 8.5. Total bagasse both boilers = 965,647 TPY**	

Segment Description and Rate: Segment 2 of 5

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Electric Utility Boiler - Wood Fired Boiler**	
2. Source Classification Code (SCC): **1-01-009-03**	
3. SCC Units: **tons burned**	
4. Maximum Hourly Rate: **69.091**	5. Maximum Annual Rate: **605,236**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.11**	8. Maximum Percent Ash: **3.2**
9. Million Btu per SCC Unit: **11**	
10. Segment Comment (limit to 200 characters): **Total wood waste both boilers = 623,055 TPY**	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 3 of 5

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Electric Utility Boiler - Distillate Oil - Grades 1 and 2 Oil**	
2. Source Classification Code (SCC): **1-01-005-01**	
3. SCC Units: **1,000 gal burned**	
4. Maximum Hourly Rate: **4.348**	5. Maximum Annual Rate: **13,942**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.05**	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **138**	
10. Segment Comment (limit to 200 characters): **Maximum Annual Rate: 13,942.251. Total No.2 Fuel Oil both boilers = 13,942,251 gal/yr. This represents 24.9% oil firing on a heat input basis.**	

Segment Description and Rate: Segment 4 of 5

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Electric Utility Boiler - Bituminous Coal - Spreader Stoker**	
2. Source Classification Code (SCC): **1-01-002-04**	
3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **22.084**	5. Maximum Annual Rate: **14,883**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.7**	8. Maximum Percent Ash: **3.7**
9. Million Btu per SCC Unit: **24**	
10. Segment Comment (limit to 200 characters): **Total coal both boilers = 14,883 TPY. This represents 5.44% coal burning on a heat input basis.**	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 5 of 5

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Electric Utility Boiler - Solid Waste - Tire-Derived Fuel**	
2. Source Classification Code (SCC): **1-01-012-01**	
3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **11.94**	5. Maximum Annual Rate: **36,537**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **1.2**	8. Maximum Percent Ash: **4.9**
9. Million Btu per SCC Unit: **31**	
10. Segment Comment (limit to 200 characters): **Max hourly rate = 370 MMBtu/hr TDF. Total TDF both boilers = 36,537 TPY. This represents 13.8% TDF on a heat input basis (5.4% on a weight basis)**	

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters):	
2. Source Classification Code (SCC):	
3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit:	
10. Segment Comment (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
H114	048		EL
PB	010		EL
H021	010		EL
PM	010		EL
PM10	010		EL
SO2			EL
NOx	107		EL
CO			EL
VOC			EL
FL			EL
SAM			EL
HAPS			NS
H106			NS
H107			NS

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: H114			
2. Total Percent Efficiency of Control:	25 %		
3. Potential Emissions:	0.0045 lb/hour	0.0168 tons/year	
4. Synthetically Limited?	[x] Yes	[ ] No	
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr			
6. Emission Factor: See Part B Reference:			
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5			
8. Calculation of Emissions (limit to 600 characters): See Part B			
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): 0.0168 TPY total both boilers			

Emissions Unit Information Section 2 **of** 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code:
   OTHER

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
   3.5 E-06 lb/MMBtu

4. Equivalent Allowable Emissions: **0.0027** lb/hour **0.0123** tons/year

5. Method of Compliance (limit to 60 characters):
   EPA Method 101A

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):
   Emission limit is for bagasse. Emission limit for wood waste is 4.0E-06 lb/MMBtu.

B.

1. Basis for Allowable Emissions Code: **OTHER**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
   2.4 E-06 lb/MMBtu

4. Equivalent Allowable Emissions: **0.0014** lb/hour **0.0019** tons/year

5. Method of Compliance (limit to 60 characters):
   EPA Method 101A

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):
   Based on No.2 fuel oil firing.

Emissions Unit Information Section 2 of 2
Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **8.4 E-06 lb/MMBtu**	
4. Equivalent Allowable Emissions: **0.0045** lb/hour	**0.0015** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 101A**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on coal firing**	

B.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **6.5 E-06 lb/MMBtu**	
4. Equivalent Allowable Emissions: **0.0024** lb/hour	**0.0037** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 101A**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on tire-derived fuel firing.**	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **PB**

2. Total Percent Efficiency of Control: **98** %

3. Potential Emissions: **0.12** lb/hour **0.22** tons/year

4. Synthetically Limited? [**X**] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ____________ to ____________ tons/yr

6. Emission Factor: **See Part B**

   Reference:

7. Emissions Method Code:

   [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   See Part B

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   0.27 TPY total for both boilers

Emissions Unit Information Section 2 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 2.7 E-06 lb/MMBtu	
4. Equivalent Allowable Emissions: 0.0021 lb/hour	0.22 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 12	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on bagasse firing. Limit for woodwaste is 1.6E-04 lb/MMbtu.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 8.9 E-07 lb/MMBtu	
4. Equivalent Allowable Emissions: 0.0005 lb/hour	0.0007 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 12	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on No.2 fuel oil firing.	

Emissions Unit Information Section 2 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code:
   OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
   5.1 E-06 lb/MMBtu
4. Equivalent Allowable Emissions: 0.0027 lb/hour 0.0009 tons/year
5. Method of Compliance (limit to 60 characters):
   EPA Method 12
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):
   Based on coal firing.

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
   4.2 E-05 lb/MMBtu
4. Equivalent Allowable Emissions: 0.0155 lb/hour 0.024 tons/year
5. Method of Compliance (limit to 60 characters):
   EPA Method 12
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):
   Based on tire-derived fuel firing.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **H021**
2. Total Percent Efficiency of Control: **98** %
3. Potential Emissions: **0.0031** lb/hour **0.0011** tons/year
4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr
6. Emission Factor: **5.9 E-06 lb/MMBtu**   Reference: **See Part B**
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters):   **5.9E-06 lb/MMBtu x 530 MMBtu/hr = 0.0031 lb/hr**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):   **Based on coal firing. 0.0013 TPY total for both boilers.**

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 3.5 E-07 lb/MMBtu	
4. Equivalent Allowable Emissions: 0.0002 lb/hour	0.0003 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 104	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Equivalent Allowable Emissions = 0.00027 TPY. Based on No.2 fuel oil firing.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 5.9 E-06 lb/MMBtu	
4. Equivalent Allowable Emissions: 0.0031 lb/hour	0.0011 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 104	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on coal firing.	

Emissions Unit Information Section 2 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **4.5 E-07 lb/MMBtu**
4. Equivalent Allowable Emissions: **0.0002** lb/hour **0.0003** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 104**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Equivalent Allowable Emissions: 0.00017 lbs/hr; 0.00025 tons/yr. Based on tire-derived fuel firing.**

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: PM

2. Total Percent Efficiency of Control: 98 %

3. Potential Emissions: 22.8 lb/hour 99.9 tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 __________ to __________ tons/yr

6. Emission Factor: 0.03 lb/MMBtu

   Reference: 40 CFR 60 Subpa Da

7. Emissions Method Code:

   [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

8. Calculation of Emissions (limit to 600 characters):

   0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   123.12 TPY total for both boilers

Emissions Unit Information Section 2 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: RULE	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.03 lb/MMBtu	
4. Equivalent Allowable Emissions: 22.8 lb/hour	99.9 tons/year
5. Method of Compliance (limit to 60 characters): Annual Stack testing using EPA Method 5.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): 40 CFR 60, Subpart Da. Maximum lb/hr based on biomass firing.	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lb/hour	tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **PM10**
2. Total Percent Efficiency of Control: 98 %
3. Potential Emissions: 22.8 lb/hour 99.9 tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: 0.03 lb/MMBtu Reference: 40 CFR 60 Subpart Da
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5
8. Calculation of Emissions (limit to 600 characters): **0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **123.12 TPY total for both boilers**

Emissions Unit Information Section 2 of 2
Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: RULE		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units: 0.03 lb/MMBtu		
4. Equivalent Allowable Emissions:	22.8 lb/hour	99.9 tons/year
5. Method of Compliance (limit to 60 characters): Annual Stack Test using EPA Method 5		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): 40 CFR 60, Subpart Da. Maximum lb/hr based on biomass firing.		

B.

1. Basis for Allowable Emissions Code:		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units:		
4. Equivalent Allowable Emissions:	lb/hour	tons/year
5. Method of Compliance (limit to 60 characters):		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SO2
2. Total Percent Efficiency of Control: %
3. Potential Emissions: 636 lb/hour 315 tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: 1.2 lb/MMBtu Reference: 40 CFR 60 Subpart Da
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5
8. Calculation of Emissions (limit to 600 characters): 1.2 lb/MMBtu x 530 MMBtu/hr Coal = 636.0 lb/hr
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): 339.0 TPY total for both boilers

Emissions Unit Information Section 2 of 2
Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: RULE	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 1.2 lb/MMBtu	
4. Equivalent Allowable Emissions: 636 lb/hour	315 tons/year
5. Method of Compliance (limit to 60 characters): Limit coal burning to 5.4% of heat input for facility.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): 40 CFR 60, Subpart Da. Based on coal firing	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.05 lb/MMBtu	
4. Equivalent Allowable Emissions: 30 lb/hour	39 tons/year
5. Method of Compliance (limit to 60 characters): Limit fuel oil burning to 24.9% for any single boiler	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on No.2 fuel oil firing and BACT.	

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: See Comment	
4. Equivalent Allowable Emissions: 76 lb/hour	106.5 tons/year
5. Method of Compliance (limit to 60 characters): Continuous SO2 monitor	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Requested Allowable Emissions and Units: 0.1 lb/MMBtu 24-hr avg; 0.02 lb/MMBtu(annual average) for bagasse, and 0.05 lb/MMBtu(annual avg) for woodwaste. Based on biomass firing & fuel sulfur content.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: See Comment	
4. Equivalent Allowable Emissions: 444 lb/hour	226.6 tons/year
5. Method of Compliance (limit to 60 characters): Continuous SO2 monitor.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Requested allowable emissions: 1.2 lb/MMBtu, 24-hr avg.; 0.4 lb/MMBtu, annual avg. Based on tire-derived fuel firing.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: NOx
2. Total Percent Efficiency of Control: 40 %
3. Potential Emissions: 121.4 lb/hour 510.7 tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: 0.15 lb/MMBtu Reference: Based on NOx control
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): Hourly: 0.15 lb/MMBtu x 390 MMBtu/hr Biomass = 58.5 lb/hr; 0.17 lb/MMBtu x 370 MMBtu/hr TDF = 62.9 lb/hr; Total = 58.5 + 62.9 = 121.4 lb/hr.
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): 626.9 TPY total for both boilers

Emissions Unit Information Section 2 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: ESCPSD
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.15 lb/MMBtu
4. Equivalent Allowable Emissions: 114 lb/hour 499.4 tons/year
5. Method of Compliance (limit to 60 characters): Annual stack test using EPA Method 7 or 7E
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on biomass firing

B.

1. Basis for Allowable Emissions Code: ESCPSD
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.15 lb/MMBtu
4. Equivalent Allowable Emissions: 90 lb/hour 117.1 tons/year
5. Method of Compliance (limit to 60 characters): Limit fuel oil burning to 24.9% for any single boiler
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on No.2 fuel oil firing

Emissions Unit Information Section 2 **of** 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **ESCPSD**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.17 lb/MMBtu**	
4. Equivalent Allowable Emissions: **90.1** lb/hour	**30.4** tons/year
5. Method of Compliance (limit to 60 characters): **Limit coal burning to 5.44% for any single boiler**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on coal firing**	

B.

1. Basis for Allowable Emissions Code: **ESCPSD**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.17 lb/MMBtu**	
4. Equivalent Allowable Emissions: **62.9** lb/hour	**96.3** tons/year
5. Method of Compliance (limit to 60 characters): **See Comment**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Method of Compliance: Annual stack testing using EPA Method 7 or 7E. Limit TDF Firing to 17% on an annual basis. Based on tire-derived fuel firing.**	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: CO		
2. Total Percent Efficiency of Control:	%	
3. Potential Emissions:	266 lb/hour	1,165.1 tons/year
4. Synthetically Limited? [x] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr		
6. Emission Factor: 0.35 lb/MMBtu Reference: Boiler design		
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5		
8. Calculation of Emissions (limit to 600 characters): 0.35 lb/MMBtu x 760 MMBtu/hr = 266 lb/hr		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): Hourly emissions represent 24-hr average. 1,436.4 TPY total for both boilers		

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.35 lb/MMBtu	
4. Equivalent Allowable Emissions: 266 lb/hour	1,165.1 tons/year
5. Method of Compliance (limit to 60 characters): Continuous CO monitor	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on biomass firing; limit is 24-hr avg.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.35 lb/MMBtu	
4. Equivalent Allowable Emissions: 210 lb/hour	273.2 tons/year
5. Method of Compliance (limit to 60 characters): Limit fuel burning to 24.9% for any single boiler	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on No.2 fuel oil firing; limit is 24-hr avg.	

Emissions Unit Information Section 2 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.35 lb/MMBtu**	
4. Equivalent Allowable Emissions: **185.5** lb/hour	**62.5** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10 annually**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on coal firing. Limit coal burning to 4.4% entire facility; 5.44% for any single boiler; limit is 24-hr avg.**	

B.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.35 lb/MMBtu**	
4. Equivalent Allowable Emissions: **129.5** lb/hour	**198.3** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10 annually.**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on tire-derived fuel firing. Limit is 24-hr avg. TDF limited to 25% for each boiler on hourly basis.**	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **VOC**
2. Total Percent Efficiency of Control: %
3. Potential Emissions: **45.6** lb/hour **173.1** tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: **0.06 lb/MMBtu** Reference: **Boiler design**
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): **0.06 lb/MMBtu x 760 MMBtu/hr = 45.6 lb/hr**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **Based on biomass firing**

Emissions Unit Information Section 2 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: ESCNAA	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: See Comment	
4. Equivalent Allowable Emissions: 45.6 lb/hour	173.1 tons/year
5. Method of Compliance (limit to 60 characters): Annual stack test using EPA Method 25 or 25A	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on biomass firing. Requested Allowable Emissions and Units: 0.06 lb/MMBtu bagasse; 0.04 lb/MMBtu wood waste.	

B.

1. Basis for Allowable Emissions Code: ESCNAA	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 0.03 lb/MMBtu	
4. Equivalent Allowable Emissions: 18 lb/hour	23.4 tons/year
5. Method of Compliance (limit to 60 characters): Limit fuel burning to 24.9% for any single boiler	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on No.2 fuel oil firing	

Emissions Unit Information Section 2 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **ESCNAA**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.03** **lb/MMBtu**	
4. Equivalent Allowable Emissions: **15.9** lb/hour	**5.36** tons/year
5. Method of Compliance (limit to 60 characters): **Limit coal burning to 5.44% for any single boiler**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on coal firing**	

B.

1. Basis for Allowable Emissions Code: **ESCNAA**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.04** **lb/MMBtu**	
4. Equivalent Allowable Emissions: **14.8** lb/hour	**22.7** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25 or 25A annually.**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on tire-derived fuel firing. TDF limited to 25% for any single boiler on hourly basis.**	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: FL			
2. Total Percent Efficiency of Control:	%		
3. Potential Emissions:	12.7 lb/hour	4.29 tons/year	
4. Synthetically Limited?	[x] Yes	[ ] No	
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3	______ to ______ tons/yr		
6. Emission Factor: 0.024 lb/MMBtu Reference: See Part B			
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5			
8. Calculation of Emissions (limit to 600 characters): 0.024 lb/MMBtu x 530 MMBtu/hr = 12.7 lb/hr			
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): Based on coal firing			

Emissions Unit Information Section 2 of 2
Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units: See Comment		
4. Equivalent Allowable Emissions:	0.0038 lb/hour	0.005 tons/year
5. Method of Compliance (limit to 60 characters):		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Allowable emissions: 6.3E-06 lb/MMBtu. Based on No.2 fuel oil firing.		

B.

1. Basis for Allowable Emissions Code: OTHER		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units: 0.024 lb/MMBtu		
4. Equivalent Allowable Emissions:	12.7 lb/hour	4.29 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 13A or 13B once every 5 years.		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Based on coal firing.		

Emissions Unit Information Section 2 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **See Comment**	
4. Equivalent Allowable Emissions: **0.24** lb/hour	**0.37** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 13A or 13B once every 5 years.**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on tire-derived fuel firing**	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lb/hour	tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SAM

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 5.6 lb/hour 4.83 tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor: 0.01 lb/MMBtu

   Reference: See Part B

7. Emissions Method Code:

   [ ] 0 [ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   0.0049 lb/MMBtu x 390 MMBtu/hr = 1.91 lb/hr; 0.010 lb/MMBtu x 370 MMBtu/hr = 3.7 lb/hr. Total = 1.91 + 3.7 = 5.6 lb/hr

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

   Based on biomass/TDF firing. Total both boilers = 6.0 TPY

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units: **0.0049 lb/MMBtu,24-hr**		
4. Equivalent Allowable Emissions:	**3.72** lb/hour	**3.26** tons/year
5. Method of Compliance (limit to 60 characters): **Method 8 once every 5 years**		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on biomass firing. Annual average based on 0.00098 lb/MMBtu.**		

B.

1. Basis for Allowable Emissions Code: **OTHER**		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units: **0.0025 lb/MMBtu**		
4. Equivalent Allowable Emissions:	**1.5** lb/hour	**1.95** tons/year
5. Method of Compliance (limit to 60 characters):		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on No.2 fuel oil firing**		

Emissions Unit Information Section 2 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.01 lb/MMBtu**	
4. Equivalent Allowable Emissions: **5.3** lb/hour	**1.8** tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on coal firing**	

B.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **0.01 lb/MMBtu**	
4. Equivalent Allowable Emissions: **3.7** lb/hour	**1.93** tons/year
5. Method of Compliance (limit to 60 characters): **Method 8 once every 5 years**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Based on tire derived fuel firing. Annual average based on 0.0034 lb/MMBtu.**	

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitations: Visible Emissions Limitation 1 of 1

1.	Visible Emissions Subtype: VE20	
2.	Basis for Allowable Opacity: [x] Rule [ ] Other	
3.	Requested Allowable Opacity Normal Conditions: 20. % Exceptional Conditions: 27. % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4.	Method of Compliance: EPA Method 9	
5.	Visible Emissions Comment (limit to 200 characters): 40 CFR 60, Subpart Da	

Visible Emissions Limitations: Visible Emissions Limitation _____ of _____

1.	Visible Emissions Subtype:	
2.	Basis for Allowable Opacity: [ ] Rule [ ] Other	
3.	Requested Allowable Opacity Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4.	Method of Compliance:	
5.	Visible Emissions Comment (limit to 200 characters):	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System Continuous Monitor 1 of 6

1. Parameter Code: VE	2. Pollutant(s):
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Durag Model Number: DR281-31-AV	Serial Number: 31505
5. Installation Date: 05 Dec 1995	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): 40 CFR 60, Subpart Da	

Continuous Monitoring System Continuous Monitor 2 of 6

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Thermo Environmental Instruments Model Number: 42D	Serial Number: 42D-53474-296
5. Installation Date: 05 Dec 1995	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): 40 CFR 60, Subpart Da	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System Continuous Monitor 3 of 6

1. Parameter Code: EM	2. Pollutant(s): SO2
3. CMS Requirement: [ ] Rule [x] Other	
4. Monitor Information: Monitor Manufacturer: Thermo Environmental Instruments Model Number: 43B Serial Number: 43B-53227-295	
5. Installation Date: 05 Dec 1995	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): 40 CFR 60, Subpart Da	

Continuous Monitoring System Continuous Monitor 4 of 6

1. Parameter Code: EM	2. Pollutant(s): CO
3. CMS Requirement: [ ] Rule [X] Other	
4. Monitor Information: Monitor Manufacturer: Thermo Environmental Instruments Model Number: 48 Serial Number: 48-53334-296	
5. Installation Date: 05 Dec 1995	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters):	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System Continuous Monitor 5 of 6

1. Parameter Code: O2	2. Pollutant(s):
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Yokogowa Model Number: ZA8C Serial Number: JJ113PA189	
5. Installation Date: 05 Dec 1995	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): 40 CFR 60, Subpart Da	

Continuous Monitoring System Continuous Monitor 6 of 6

1. Parameter Code: CO2	2. Pollutant(s):
3. CMS Requirement: [ ] Rule [X] Other	
4. Monitor Information: Monitor Manufacturer: California Analytical Model Number: ZARH1 Serial Number: N5B3535T	
5. Installation Date: 05 Dec 1995	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters):	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

   If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

   [x] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and the emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and the emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[x] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3.	Increment Consuming/Expanding Code:			
	PM	[x] C	[ ] E	[ ] Unknown
	SO_2	[x] C	[ ] E	[ ] Unknown
	NO_2	[x] C	[ ] E	[ ] Unknown
4.	Baseline Emissions:			
	PM	lb/hour		tons/year
	SO_2	lb/hour		tons/year
	NO_2			tons/year
5.	PSD Comment (limit to 200 characters):			

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements for All Applications

1.	Process Flow Diagram [X] Attached, Document ID: PART B [ ] Not Applicable	[ ] Waiver Requested
2.	Fuel Analysis or Specification [X] Attached, Document ID: PART B [ ] Not Applicable	[ ] Waiver Requested
3.	Detailed Description of Control Equipment [X] Attached, Document ID: PART B [ ] Not Applicable	[ ] Waiver Requested
4.	Description of Stack Sampling Facilities [ ] Attached, Document ID: ______ [X] Not Applicable	[ ] Waiver Requested
5.	Compliance Test Report [ ] Attached, Document ID: ______ [ ] Previously Submitted, Date: ______	[X] Not Applicable
6.	Procedures for Startup and Shutdown [ ] Attached, Document ID: ______	[X] Not Applicable
7.	Operation and Maintenance Plan [ ] Attached, Document ID: ______	[X] Not Applicable
8.	Supplemental Information for Construction Permit Application [X] Attached, Document ID: PART B	[ ] Not Applicable
9.	Other Information Required by Rule or Statute [X] Attached, Document ID: PART B	[ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

10.	Alternative Methods of Operation [ ] Attached, Document ID: ____________ [ ] Not Applicable
11.	Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID: ____________ [ ] Not Applicable
12.	Identification of Additional Applicable Requirements [ ] Attached, Document ID: ____________ [ ] Not Applicable
13.	Compliance Assurance Monitoring Plan [ ] Attached, Document ID: ____________ [ ] Not Applicable
14.	Acid Rain Permit Application (Hard Copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: ____________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: ____________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: ____________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: ____________ [ ] Not Applicable

PART B

SUPPLEMENTAL INFORMATION FOR PERMIT APPLICATION

OSCEOLA POWER LIMITED PARTNERSHIP

1.0 INTRODUCTION

Osceola Power Limited Partnership (Osceola) was issued a prevention of significant deterioration (PSD) permit in 1993 for construction of a 74 megawatt electric (MWe) cogeneration facility. In 1995, a revised construction permit was issued to incorporate certain design changes (Permit No. AC50-269980; PSD-FL-197A). The cogeneration facility is located adjacent to the existing Osceola Farms sugar mill, east of Pahokee, Florida. The cogeneration facility was designed to combust primarily biomass (bagasse and wood waste materials) to generate steam and electricity. The facility was also designed to supply the adjacent sugar mill with process steam during the sugar cane grinding season, approximately November through March.

Construction was completed on the facility in 1995, and initial operations began in October 1995. Due to technical and operational difficulties and periods of facility shutdown, the facility was operated at less than design capacity during 1996. Almost all fuel burned in the facility boilers has been wood waste and No. 2 fuel oil. Only a small amount of bagasse has been combusted.

To date, the cogeneration facility has been unable to successfully connect to the sugar mill. Once the facility successfully connects to the sugar mill, the existing sugar mill boilers will be shutdown and will only operate when one or more of the cogeneration units are shutdown. The existing sugar mill boilers will be permanently shutdown and rendered incapable of operation no later than January 1, 1999.

The cogeneration facility will provide enough steam energy for the needs of the Osceola Farms sugar mill and will generate electricity which will be sold to Florida Power & Light Company (FPL). Further, the cogeneration facility will reduce overall air emissions and water consumption compared to the existing sugar mill facility. In addition, approximately 18 times more electric energy from the cogeneration facility will be produced than in the existing sugar mill facility boilers.

The original state construction permit (AC50-219795) and federal PSD permit (PSD-FL-197) were issued to Osceola on September 27, 1993. The permit was modified on October 16, 1995 (AC50-269980; PSD-FL-197A) to reflect certain design changes in the facility since the original permits were issued. In 1996, Osceola submitted a construction permit application to burn tire-derived fuel (TDF) as a supplemental fuel to biomass. This application is currently being held in abeyance pending the results of a TDF trial burn.

Initial compliance testing was performed at Osceola during December of 1996. According to the air construction permit, Specific Condition No. 23, compliance tests are to be conducted every 6 months for a period of 2 years in order to confirm the emission limits for certain pollutants in the permit. Based on the results of these tests, emission limits can be revised as long as a fuel management plan is submitted to demonstrate that annual emission limits (in tons per year) for the facility will not be exceeded.

Test data gathered from the facility to date, which includes the compliance test data as well as data from the continuous emission monitoring system (CEMS), indicates that the emission limits for sulfur dioxide (SO_2), lead (Pb), and mercury (Hg) need to be revised. In addition, it is requested that the averaging time associated with the biomass emission limit for carbon monoxide (CO) be increased, and that the CO emission limit for fuel oil and coal be increased. Also, Osceola desires to increase the NO_x emission limit to be consistent with the NO_x limit at Okeelanta Power Limited Partnership (Okeelanta).

The requested changes in the permit limits will not increase permitted annual emissions to the atmosphere of PSD regulated pollutants, except for NO_x and small increases in the annual emissions of lead. Emission increases for lead (<0.6 TPY) do not require PSD or nonattainment new source review. However, PSD review is required for NO_x since emissions are increasing by greater than 40 TPY.

This report presents a description of the proposed emission limit changes, and the rational and supporting information for such changes. A complete description of the requested changes, including air emission rates, is presented in Section 2.0. The air quality review requirements for the project and new source review applicability are discussed in Section 3.0. The Best Available Control Technology (BACT) analysis for NO_x is provided in Section 4.0. An air modeling analysis for NO_x and an updated air modeling analysis for air toxics is presented in Section 5.0. Additional impact analyses are presented in Section 6.0.

2.0 PROJECT DESCRIPTION

2.1 GENERAL

Osceola was issued a state construction permit (AC50-269980) and federal PSD permit (PSD-FL-197A) on September 27, 1993, for the construction of a 74 MWe (gross) capacity biomass/coal-fired cogeneration facility. The cogeneration facility consists of two steam boilers and one steam turbine and associated equipment. Each boiler is capable of producing an average of 506,000 lbs/hr steam. During the sugar processing season, the cogeneration facility is to provide steam to the existing Osceola Farms sugar mill by burning primarily bagasse, which is the cellulose fiber coproduct resulting from the sugar cane grinding process, while also generating electricity. During the off-season, the cogeneration facility will burn primarily wood waste to generate electricity.

The current construction permit limits the maximum heat input to each of the two boilers to 760 million British thermal units per hour (MMBtu/hr) when firing biomass, 600 MMBtu/hr when firing No. 2 fuel oil, and 530 MMBtu/hr when firing low sulfur coal. Maximum annual heat input to the entire facility is limited to 8.208×10^{12} Btu/yr. Maximum annual coal burning is limited to 18,221 tons per year (TPY), which is approximately 5.4 percent of the total maximum annual heat input to the facility.

In addition to the currently permitted fuels, it has been proposed by Osceola (in June 1996) to permit tire-derived fuel (TDF) as a supplemental fuel to be used primarily in the off-season when bagasse is not available. TDF may also be burned during the crop season in order to extend the bagasse fuel supply. TDF will be fired in combination with biomass. The proposed maximum hourly TDF input was 25 percent on a weight basis (23,871 lb/hr or 11.94 TPH, maximum) and 16.5 percent (weight basis) on a facility-wide annual average basis (43,867 TPY total TDF).

The changes to the facility operating and emission limits now being proposed by Osceola consist of the following:

1. Adjustment of the SO_2, Pb, and Hg emission limits for wood waste fuel,
2. Adjustment of the Hg emission limit for bagasse burning,
3. Adjustment of the NO_x emission limit for all fuels,
4. Adjustment in the expected mix of bagasse and wood waste fuels,

5. Adjustment of the averaging time associated with the facility CO emission limits, and increase of the CO emission limit for fuel oil and coal firing , and
6. Adjustment of the annual coal and TDF firing rates in order to not exceed facility emission caps for SO_2 and Hg.

The two new boilers are subject to federal new source performance standards (NSPS) for electric utility boilers (40 CFR 60, Subpart Da). Because the facility will burn wood waste potentially originating from residential sources, the boilers are also subject to a reporting and record keeping requirement under 40 CFR 60, Subparts Ea and Cb, which are the NSPS for municipal waste combustors. Because of the broad definition of municipal solid waste (MSW), wood waste is potentially classified as municipal solid waste. Because Osceola will limit the total amount of MSW fired in each boiler to less than 30 percent (weight basis) on a calendar quarter basis, no provisions of Subparts Ea and Cb will apply to the facility, other than the record keeping and reporting requirements.

Air pollution control equipment serving each boiler consists of an electrostatic precipitator (ESP) to control particulate matter (PM) and heavy metal emissions, a selective non-catalytic reduction (SNCR) system for the control of NO_x emissions, and a mercury control system.

A regional map showing the location of the site is presented in Figure 2-1. A location map showing the existing sugar mill, cogeneration site, and plant property boundaries is presented in Figure 2-2.

2.2 COGENERATION FACILITY DESIGN INFORMATION

Current design and operating information concerning the cogeneration facility was presented in the application for TDF firing submitted in May, 1996. Most of this information has not changed; where there are changes, the information is presented in the following sections. A simplified process flow diagram of the cogeneration facility is presented in Figure 2-3.

2.2.1 FUELS

Osceola desires to burn only biomass fuels. It is planned that the bagasse from the sugar grinding operation will provide approximately 60 percent of the annual fuel requirements of the facility. The remaining fuel requirements will be provided by wood waste materials, which could include clean construction and demolition wood debris, yard trimmings, land clearing debris, and other clean cellulose and vegetative matter. However, because wood waste materials are not commodity fuels and the supply of wood waste may fluctuate, it is necessary to have the ability to burn limited amounts of other fuels in the event that the supply of biomass fuel is not adequate. Therefore, each combustion unit has the capability to burn biomass, biomass/TDF, very low sulfur fuel oil, and coal.

Fuel specifications for each fuel that may be utilized by the cogeneration facility, including TDF, are presented in Table 2-1. Based on these fuel specifications, maximum hourly firing rates are shown in Table 2-2 for each fuel when fired alone. The maximum heat input to each boiler due to biomass fuels is 760 MMBtu/hr. Due to limitations of the fuel oil firing system, maximum heat input of No. 2 fuel oil is limited to 600 MMBtu/hr. Maximum heat input due to coal will be 530 MMBtu/hr. Biomass and fossil fuels may also be burned in combination, not to exceed a total heat input of 760 MMBtu/hr per boiler. These maximum heat input rates are the same as the current permitted rates.

TDF will always be burned in combination with biomass. Maximum TDF input to each boiler will not exceed 25 percent on a weight basis (approximately 48 percent on a heat input basis), up to a maximum of 23,871 lb/hr (11.94 TPH and 370 MMBtu/hr). Biomass and TDF, burned in combination, will not exceed a total heat input of 760 MMBtu/hr.

On an annual basis, all fuels may be fired alone or in combination, not to exceed a total heat input for both boilers of 8.208×10^{12} Btu/yr. Burning of No. 2 fuel oil will be limited to a total of 24.9 percent of the total annual heat input. Coal burning will be limited to 4.4 percent annually on a heat input basis (compared to the current permit limitation of 5.4% annually), or 14,883 TPY. TDF burning will be limited to 13.8 percent annually on a facility-wide basis heat input basis (compared to 16.5% in the current permit), or to 36,537 TPY total for the facility.

Four cases are shown in Table 2-2 to illustrate the anticipated scenario of firing 100 percent biomass fuel and the potential cases of firing the maximum amount of fuel oil, coal or TDF, with the remaining heat input due to biomass. When only biomass is fired, the annual heat input requirement is 8.208×10^{12} Btu/yr for the entire facility (total both boilers). On an annual basis, it is expected that bagasse will provide 60 percent of the biomass heat input, with wood waste providing 40 percent.

Under the worst-case fuel oil burning case of firing No. 2 fuel oil at 24.9 percent of the total annual heat input, the annual heat input requirement for the entire facility becomes 7.727×10^{12} Btu/yr, due to the different heat transfer efficiency for No. 2 fuel oil versus biomass. Similarly, under the worst-case coal firing case of firing coal at 4.4 percent of the total annual heat input, the annual heat input requirement for the entire facility becomes 8.118×10^{12} Btu/yr. Under the worst-case TDF firing case of 13.8 percent of the total annual heat input (5.4 percent on a weight basis), the annual heat input for the entire facility is 8.208×10^{12} Btu/yr.

2.2.2 FACILITY PLOT PLAN

A plot plan of the Osceola cogeneration facility is presented in Figure 2-4. This diagram indicates the biomass and TDF storage areas.

2.2.3 CONTROL EQUIPMENT INFORMATION

The cogeneration facility utilizes several emission control techniques to reduce emissions. A selective non-catalytic reduction (SNCR) system is used to reduce NO_x emissions. SNCR is a system which injects urea into the boiler to reduce NO_x emissions. Further, the cogeneration boilers minimize CO and VOC through proper furnace design and good combustion practices, including: control of combustion air and combustion temperature; distribution of fuel on the combustion grate; and better controls over the furnace loads and transient conditions. Particulate emissions are controlled by an electrostatic precipitator (ESP). Mercury emissions are controlled through a carbon injection system and the ESP system.

The mercury control system is supplied by ABB Environmental Systems and Chemco, Inc. A volumetric feeder with integral supply hopper meters activated carbon for injection at a point in the ductwork between the furnace and the ESP. This promotes turbulent mixing and provides adequate residence time. A blower system transports the carbon to the injection point. The ESP will effectively capture the activated carbon particles along with the boiler fly ash (which also contains some carbon). The system is designed to inject up to 32 lb/hr of carbon into the flue gases of each boiler.

2.2.4 STACK PARAMETERS

Stack parameters for the cogeneration facility are presented in Table 2-3. The parameters reflect actual operating data based on the compliance testing. Each of the two boilers are served by a separate stack. The top of each stack is 225 feet (ft) above ground. Each stack is 10.0 ft in diameter. The locations of the two stacks are shown in Figure 2-4.

2.3 REVISIONS TO BOILER EMISSION LIMITS

2.3.1 LIMITS FOR CRITERIA/DESIGNATED POLLUTANTS

The emission limits for all criteria/designated pollutants emitted by the Osceola boilers are presented in Table 2-4. The emission limits in terms of lb/MMBtu, lb/hr and tons per year (TPY) are all the same as currently permitted, except for the changes described below. These revisions are being requested due to higher than expected levels of sulfur, lead and mercury in the wood waste fuel. In addition, there are several operational factors which dictate that changes in CO emission limits and averaging times be implemented.

The basis for these permit revisions are described below. Throughout the following discussions, test data and fuel analysis from the Okeelanta facility are presented. Due to the use of fuels from the same suppliers, and the similarity of the boilers and control equipment, the data are applicable to the Osceola facility.

2.3.1.1 Nitrogen Oxides

The current permit limit for NO_x emissions for biomass fuel is 0.12 lb/MMBtu based on a 30-day rolling average. Thus, the limits for bagasse and wood waste are the same. In order to comply with this limit, SNCR is employed by injecting urea to the boilers. The operation of the SNCR system is very costly due to several reasons. Urea addition is high in order to control NO_x emissions to the current permit limit. The cost of purchasing the additional urea to meet this stringent limit is very high, compared to the Okeelanta facility where the limit is 0.15 lb/MMBtu. At Osceola, the boilers have experienced several superheater tube failures due to corrosion. The additional urea injection at Osceola required to meet the 0.12 lb/MMBtu NO_x limit is believed to be a contributor to this corrosion problem. These failures are costly to repair and also cause significant down time for the boiler, resulting in loss of operating time and revenues from electrical generation.

Osceola requests that the current NO_x limit be increased to 0.15 lb/MMBtu as a 30-day rolling average. This is the same limit that Okeelanta is currently operating under. It is requested that the NO_x limits for fuel oil be revised to 0.15 lbs/MMBtu, and for coal and TDF to 0:17 lbs/MMBtu. These requested limits are consistent with the NO_x limits for Okeelanta for other fuels. A BACT analysis for NO_x emissions is presented in Section 4.0.

2.3.1.2 Sulfur Dioxide

The current permit limits for SO_2 emissions from biomass fuel are 0.1 lb/MMBtu for a 24-hour average, and 0.02 lb/MMBtu as a 30-day rolling average. Thus, the limits for bagasse and wood waste are the same. At the time of the original permit application, very little information was available regarding the sulfur content of wood wastes. Based on limited data from the Okeelanta sugar mill, it was concluded that the sulfur contents of the two fuels were similar. The limits were based on sulfur contents of 0.045% (max) and 0.009% (avg.), wet basis. Although inherent SO_2 removal in the boiler system due to the alkaline nature of wood and bagasse ash was expected, no removal was considered in calculating the equivalent SO_2 emissions.

Osceola receives wood waste from the same suppliers as Okeelanta. Based on analysis of the wood waste Okeelanta is receiving, the sulfur content of the wood waste is higher than anticipated. The data show a wide range of sulfur contents, depending on the source and/or supplier of the wood waste. Data from various suppliers are summarized in Table 2-5. As shown, the average sulfur content of wood waste from specific suppliers can range from 0.02% to 0.17% sulfur (dry basis), equivalent to 0.05 to 0.44 lb/MMBtu SO_2 emissions. The overall average of all deliveries cannot be estimated because the frequency of deliveries and quantity of wood waste delivered varies considerably for each supplier.

Data obtained to date from Okeelanta and Osceola's compliance test data shows that SO_2 emissions due to wood waste firing are in the range of 0.02 to 0.08 lb/MMBtu, and average 0.05 lb/MMBtu (see Table 2-6). CEMS data at Okeelanta for SO_2 from January-March 1997 are summarized in Table 2-7. These data indicate that significant SO_2 removal is indeed occurring in the boiler system. Although significant SO_2 capture in the alkaline fly ash is indicated, the current annual average SO_2 emission limit of 0.02 lb/MMBtu may not be achievable for wood waste. Based on the compliance testing and CEMS results, an annual average SO_2 emission limit of 0.05 lb/MMBtu is proposed for wood waste. The current limit of 0.02 lb/MMBtu for bagasse is being retained at this time. This limit, however, may be subject to revision based upon further testing with bagasse.

As a result of the proposed higher emission rate for wood waste, Osceola will reduce maximum annual coal firing to 4.4% (heat input basis) or 14,883 TPY in order to maintain total facility SO_2 emissions below the current permit limit of 339 TPY. Similarly, annual TDF firing will be limited to 13.8% annually (heat input basis), or 36,537 TPY.

2.3.1.2 Carbon Monoxide

The current limit for CO emissions from biomass burning is 0.35 lb/MMBtu based on an 8-hour averaging time. This limit was based on the boiler manufacturer's design. CO emissions data obtained to date from Okeelanta and Osceola's compliance testing are presented in Table 2-6. These data indicate that the emission limit has been achieved during the compliance tests. However, data from Osceola's CEMS for CO indicates that CO emissions due to biomass firing can exceed the emission limit based on an 8-hour averaging time. During January-April 1997, the boilers at Osceola experienced several excursions of the emission limit, with 8-hour CO averages up to 0.7 lb/MMBtu. These excursions were attributed to master fuel trips, clinker removal, improper air flow due to equipment malfunction (grate control problems), plugged fuel feeders, and changes in fuel quality.

Based on review of the CEMS data, Osceola believes that the current CO limit is achievable if it is based on a 24-hour averaging time basis. The longer averaging time will allow fluctuations in CO emissions to occur on a short-term basis, but will not increase daily or annual CO emissions. Thus, it is requested that the averaging time for the CO emission limit for biomass be revised to reflect a 24-hour block averaging time. In order to be consistent, it is requested that the averaging time for the CO limits for No. 2 fuel oil, coal, and TDF also be specified as a 24-hour block average basis.

Osceola is currently negotiating with the PBCPHU a corrective action plan (CAP) which addresses CO emissions. The proposed CAP addresses several aspects of the boiler operation, including distribution of boiler combustion air, consistent fuel feed to the boilers, boiler air leakage, boiler upset conditions, changes in fuel quality, and startup/shutdown. Osceola has recently begun blending of fuels in the storage area to produce a more homogenous fuel mix.

In regard to PBCPHU's preference for a 24-hour rolling block average, it is noted that similar type sources permitted in Palm Beach County and in Florida (Palm Beach County Resource Recovery and Wheelabrator Ridge Energy) have CO permit limits based on either 24-hour block averages (midnight-to-midnight), or 30-day rolling averages. Use of a 24-hour rolling average would not reduce total allowable annual emissions, but would add greatly to the record keeping and reporting burden for Osceola. The current software program Osceola uses for its CEMs would need to be modified as well. Discussions with PBCPHU indicate they have no objection to the 24-hour block average for CO.

In conjunction with the CO averaging time issue, at this time Osceola desires to increase the CO emission limit for both fuel oil and coal firing . The current CO limit for both of these fuels is 0.2 lb/MMBtu. While this limit can be met when firing 100% fuel oil or coal, fuel oil is often fired in conjunction with biomass in order to supplement the combustion process, providing greater combustion efficiency and lower overall CO emissions. Coal may also be fired in conjunction with biomass. Under such conditions, the fuel oil and coal may not burn as effectively as when burned alone, and the overall prorated emission limit may not be achievable at all times. The requested increase is for a CO limit for fuel oil firing and coal of 0.35 lb/MMBtu, based on a 24-hour block average (the same as for biomass firing). This request does not increase the potential CO emissions for the Osceola facility.

2.3.1.3 Lead

The current emission limit for Pb for biomass fuel is $2.7x10^{-6}$ lb/MMBtu. The limits for bagasse and wood waste are the same. At the time of the original permit application, very little information was available regarding the lead content of wood wastes or emissions of lead from wood-fired boilers. The emission limit of $2.7x10^{-6}$ lb/MMBtu was based on the average emissions from three wood-fired boilers controlled by an ESP, as reported by Sassenrath (1991).

Okeelanta has conducted analysis of delivered wood wastes for Pb content (wood waste delivered to Osceola is similar). The results of these analysis are presented in Table 2-8. As shown, the Pb content of the wood waste has ranged between 0.5 and 350 ppm. The high value of 350 ppm appears to be an outlier, as the next highest value is only 37.8 ppm. Excluding the high value, the average Pb content is 7.9 ppm. This is equivalent to uncontrolled Pb emissions of $1.0x10^{-3}$ lb/MMBtu, assuming 8,000 Btu/lb (dry) for wood waste.

Data obtained to date from Okeelanta and Osceola's compliance test data shows that Pb emissions due to wood waste firing are in the range of 1.23×10^{-5} to 13.6×10^{-5} lb/MMBtu, with an average of 5.25×10^{-5} lb/MMBtu (see Table 2-6). Compared to the Pb levels measured in the wood waste fuel, these data indicate that significant Pb removal is occurring in the ESP system. Based on the average Pb levels in the fuel, the average Pb removal efficiency is calculated to be 97 percent.

Although significant Pb capture in the ESP system is indicated, the current Pb emission limit of 2.7×10^{-6} lb/MMBtu may not be achievable for wood waste. Based on the compliance testing results, an emission limit of 1.6×10^{-4} lb/MMBtu is proposed for wood waste. This value represents the upper 95% confidence level of the compliance test data (i.e., there is 95% confidence that this value will not be exceeded during a compliance test; refer to Table 2-6). The current 2.7×10^{-6} lb/MMBtu limit for bagasse is being retained at this time. This limit, however, may be subject to revision based upon further testing on bagasse.

2.3.1.4 Mercury

The current emission limit for Hg for bagasse fuel is 5.7×10^{-6} lb/MMBtu, and for wood waste is 0.29×10^{-6} lb/MMBtu. Thus, the limits for bagasse and wood waste are different. At the time of the original permit application, very little information was available regarding the Hg content of wood wastes or emissions of Hg from wood-fired boilers. The original emission limit of 0.29×10^{-6} lb/MMBtu for wood waste was based on the average emissions from three wood fired boilers controlled by an ESP, as reported by Sassenrath (1991). A control efficiency of 30% was then applied to this emission rate based on the use of a carbon injection system for Hg control.

Okeelanta has conducted analysis of wood wastes for Hg content, and these analysis are presented in Table 2-8. As shown, the Hg content of the wood waste has ranged between 0.025 and 1.00 ppm, with an average of 0.095 ppm. This average is equivalent to uncontrolled emissions of Hg of 1.2×10^{-5} lb/MMBtu, assuming 8,000 Btu/lb (dry) for wood waste.

Data obtained to date from Okeelanta and Osceola's compliance test data, presented in Table 2-9, shows that Hg emissions due to wood waste firing are in the range of 0.95×10^{-6} to 3.23×10^{-6} lb/MMBtu, with an average of 1.90×10^{-6} lb/MMBtu. Compared to the Hg levels measured in the wood waste fuel, these data indicate that significant Hg removal is occurring in the ESP system.

Based on the average Hg levels in the fuel, the average Hg removal efficiency is calculated to be 84%.

Okeelanta has conducted several Hg emission tests for the purposing of better quantifying Hg emissions, as well as the effectiveness of the Hg removal system (carbon injection system). The results of these tests are shown in Table 2-10. As shown, three tests were conducted at each of three carbon injection rates. The amount of fuel burned and the Hg content of the fuel were utilized to calculate the Hg input to the boiler. The stack tests results were then used to calculate the amount of Hg emitted to the atmosphere. This calculation shows that the Hg removal efficiency of the system ranged from 17% to 93%, with an average of 69%. This removal efficiency is well above the 30% removal which formed the basis of the original air permit for the Osceola facility. The test data also show that the level of Hg emissions or calculated removal efficiency does not appear to be related to the amount of carbon injection.

Although significant Hg capture in the ESP system is indicated, the current Hg emission limit of 0.29×10^{-6} lb/MMBtu for wood waste appears to be too low. Based on the compliance testing results, an emission limit of 4.0×10^{-6} lb/MMBtu is proposed for wood waste. This limit represents a value somewhat greater than the highest measured Hg emission rate of 3.23×10^{-6} lb/MMBtu (refer to Table 2-9).

The current Hg limit of 5.7×10^{-6} lb/MMBtu limit for bagasse is being decreased at this time to 3.5×10^{-6} lb/MMBtu in order to maintain total annual Hg emissions from the facility at 0.0168 TPY. This limit, however, may be subject to revision based upon further testing with bagasse.

2.4 EMISSION RATES FOR REGULATED POLLUTANTS

The proposed changes to the emission limits at Osceola are summarized in Table 2-11. Based on these changes, maximum short-term emissions from each of the Osceola boilers for each fuel are presented in Table 2-12. This table reflects the proposed NO_x, SO_2, CO, Pb, and Hg emission limits for bagasse and wood waste firing. Since TDF will always be burned in combination with biomass, with up to 25 percent TDF on a weight basis, emission rates are also presented for 25 percent TDF/75 percent biomass firing (weight basis). As shown, the maximum hourly emissions occur when burning either biomass, biomass/TDF, or coal.

The total maximum annual emissions for each pollutant from both boilers, including the proposed TDF firing, are presented in Table 2-13. These are based upon the same emission factors as presented in Table 2-4 and described above. The total maximum annual emission rate for each pollutant is based upon the worst-case fuel operating scenario and is identified in the far right column of Table 2-13. The maximum annual emissions for any of the criteria/designated pollutants are not higher than currently permitted, except in the case of NO_x and Pb. Maximum annual heat input and emissions per boiler for the Osceola facility are presented in Tables 2-14 and 2-15.

2.5 TOXIC/HAZARDOUS AIR POLLUTANTS

Emissions of certain toxic or hazardous air pollutants are changing due to the proposed emission rates (e.g., for mercury, lead, etc.) and also because maximum annual firing rates for coal and TDF are changing. Revised emissions are presented in Table 2-16 (hourly) and Table 2-17 (annual average). These emissions are used in the revised dispersion modeling analysis, presented in Section 5.0.

2.6 COMPLIANCE DEMONSTRATION

Osceola will continue to demonstrate compliance with the maximum heat input limits for the facility by monitoring fuel input rates and fuel characteristics on a periodic basis. Steam production parameters (i.e., steam quantity, pressure, and temperature) and feedwater parameters will be continuously monitored to allow calculation of heat input by use of an assumed heat transfer efficiency for each fuel. In addition, per the zoning conditions recommended by Palm Beach County and agreed to by Osceola, stack testing will be performed for PM, NO_x, CO, SO_2, lead, mercury, and VOC every 6 months during the first 2 years of operation. If these tests show compliance with the permitted emission limits, the stack testing frequency will be reduced to that typically required by FDEP (i.e., once every year or once every 5 years, depending upon pollutant). Based on these tests, additional revisions of permit limitations may be required. Any such revisions will be submitted to the Department for approval.

Table 2-1. Design Fuel Specifications[a] for the Osceola Power Cogeneration Facility

Parameter	Biomass		No. 2 Fuel Oil	Bituminous Coal	Tire-Derived Fuel
	Bagasse	Wood Waste			
Specific Gravity	—	—	0.865	—	—
Heating Value (Btu/lb)	4,250	5,500	19,175	12,000	15,500
Heating Value (Btu/gal)	—	—	138,000	—	—
Ultimate Analysis (dry basis percentage):					
Carbon	48.93	49.58	87.01	82.96	84.4
Hydrogen	6.14	5.87	12.47	5.41	7.1
Nitrogen	0.25	0.40	0.02	1.58	0.24
Oxygen	43.84	40.90	0.00	5.72	2.18
Sulfur	0.009	0.009	0.50	0.67	1.23
Ash/Inorganic	0.83	3.24	0.00	3.66	4.9
Moisture	52	37	—	4.5	0.6

[a] Represents average fuel characteristics.

Sources: Okeelanta Corp., 1992.
Combustion Engineering, 1981.
Waste Recovery, Inc., 1986.

Table 2-2. Maximum Fuel Usage and Heat Input Rates, Osceola Power Limited Partnership

Type of Fuel	Heat Input	Heat Transfer Efficiency (%)	Heat Output	Fuel Firing Rate	
	Maximum Short-Term (per boiler)				
	(MMBtu/hr)		(MMBtu/hr)		
Biomass - Bagasse	760	68	517	178,824	lb/hr
- Wood Waste	760	68	517	138,182	lb/hr
No. 2 Fuel Oil	600	85	510	4,348	gal/hr
Coal	530	85	451	44,167	lb/hr
Tire-Derived Fuel	370	68	252	23,871	lb/hr
	Annual Average (total two boilers)				
	(Btu/yr)		(Btu/yr)		
NORMAL OPERATIONS					
Biomass	8.208E+12	68	5.581E+12	965,647	TPY (a)
No. 2 Fuel Oil	0	85	0	0	gal/yr
Coal	0	85	0	0	TPY
Tire-Derived Fuel	0	68	0	0	TPY
TOTAL	8.208E+12		5.581E+12		
24.9% OIL FIRING					
Biomass	5.803E+12	68	3.946E+12	682,706	TPY
No. 2 Fuel Oil	1.924E+12	85	1.635E+12	13,942,251	gal/yr
Coal	0	85	0	0	TPY
Tire-Derived Fuel	0	68	0	0	TPY
TOTAL	7.727E+12		5.581E+12		
4.4% COAL FIRING					
Biomass	7.761E+12	68	5.277E+12	913,059	TPY
No. 2 Fuel Oil	0	85	0	0	gal/yr
Coal	3.572E+11	85	3.036E+11	14,883	TPY
Tire-Derived Fuel	0	68	0	0	TPY
TOTAL	8.118E+12		5.581E+12		
13.8% TIRE-DERIVED FUEL (5.4% TDF, weight basis)					
Biomass	7.075E+12	68	4.811E+12	643,182	TPY (b)
No. 2 Fuel Oil	0	85	0	0	gal/yr
Coal	0	85	0	0	TPY
Tire-Derived Fuel	1.133E+12	68	7.702E+11	36,537	TPY
TOTAL	8.208E+12		5.581E+12		

(a) Based on bagasse firing.
(b) Based on wood waste firing.

Notes: Total heat output required = 5.581E+12 Btu/yr total both boilers.
Fuels may be burned in combination, not to exceed total heat outputs.
Based on fuel heating values as follows:
- Bagasse - 4,250 Btu/lb
- Wood Waste - 5,500 Btu/lb
- No. 2 Fuel Oil - 138,000 Btu/gal
- Coal - 12,000 Btu/lb
- Tire-derived fuel - 15,500 Btu/lb

Basis for annual heat input

Grinding season: 440,000 lb/hr steam; 658 MMBtu/hr/boiler; 140 crop days
Heat input= 4.4218E+12 Btu/yr

Non-grinding season: 273,150 lb/hr steam; 369 MMBtu/hr/boiler; 225 crop days; 95% capacity
Heat input= 3.7859E+12 Btu/yr

Totals: Heat input= 8.2077E+12 Btu/yr

Table 2-3. Stack Parameters for the Boilers at the Osceola Power Facility.

Stack Parameter	Boilers (each) Biomass	Oil	Coal	TDF/Biomass	Baghouse	Fly Ash Silo Filter	Carbon Silo Filter
Heat Input Rate (MMBtu/hr)	760	600	530	760	- -	- -	- -
Stack Height (ft)	225	225	225	225	10	110	24
Stack Diam. (ft)	10	10	10	10	4.0 x 4.0	2.0 x 2.0	2.0 x 2.0
Gas Flowrate (acfm)	246,000 - 326,000	170,000 - 184,000	228,000 - 246,000	246,000 - 326,000	30,000	1,000	1,000
Gas Velocity (ft/s)	52.2 - 69.2	36.1 - 39.0	48.4 - 52.2	52.2 - 69.2	31.3	4.2	4.2
Gas Temperature (F)	295 - 340	295 - 350	295 - 350	295 - 350	80	100	80

Table 2-4. Emission Limits for the Osceola Power Facility

Pollutant	Emission Limit per Boiler (a)										Total Both Boilers (f)
	Bagasse (b)		Woodwaste (b)		No. 2 Fuel Oil (c)		Bituminous Coal (d)		Tire-Derived Fuel (e)		
	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(TPY)
Particulate (TSP)	0.03	22.8	0.03	22.8	0.03	18.0	0.03	15.9	0.03	11.1	123.1
Particulate (PM10)	0.03	22.8	0.03	22.8	0.03	18.0	0.03	15.9	0.03	11.1	123.1
Sulfur Dioxide											
3-Hour Average	--	--	--	--	--	--	1.2	636.0	1.2	444.0	--
24-Hour Average	0.10	76.0	0.10	76.0	0.05	30.0	1.2	636.0	1.2	444.0	--
Annual Average	0.02 g,h	--	0.05 g	--	--	--	1.2 g	--	0.4 g	--	339.0 (i)
Nitrogen Oxides											
Annual Average	0.15 g	114.0 g	0.15 g	114.0 g	0.15 g	90.0 g	0.17 g	90.1 g	0.17 g	62.9 g	626.9
Carbon Monoxide											
24-Hour Average	0.35	266.0	0.35	266.0	0.35	210.0	0.35	185.5	0.35	129.5	1,436.4
VOCs	0.06 h	45.6 h	0.04	30.4	0.03	18.0	0.03	15.9	0.04	14.8	219.2
Lead	2.7E-06	0.0021	1.6E-04	0.12	8.9E-07	0.0005	5.1E-06	0.002703	4.2E-05	0.016	0.27
Mercury	3.5E-06 h	0.0027 h	4.0E-06	0.0030	2.4E-06	0.0014	8.4E-06	0.004452	6.5E-06	0.0024	0.0168
Beryllium	--	--	--	--	3.5E-07	0.00021	5.9E-06	0.003127	4.5E-07	1.7E-04	0.0013
Fluorides	--	--	--	--	6.3E-06	0.0038	0.024	12.7	6.5E-04	0.24	5.25
Sulfuric Acid Mist											
24-Hour Average	0.0049	3.72	0.0049	3.72	0.0025	1.50	0.010	5.3	0.010	3.70	--
Annual Average	0.00098	--	0.00098	--	--	--	--	--	--	--	6.0

Notes:

(a) The emission limit shall be prorated when more than one type of fuel is burned in a boiler.
(b) Biomass emissions are based on 760 MMBtu/hr.
(c) No. 2 Fuel Oil emissions are based on 600 MMBtu/hr.
(d) Bituminous Coal emissions are based on 530 MMBtu/hr.
(e) Tire-Derived Fuel (TDF) emissions are based on 370 MMBtu/hr.
(f) Limit heat input from No. 2 fuel oil to < 25% of the total heat input on a calendar quarter basis, coal to 14,883 TPY and TDF to 36,537 TPY during any 12-month period, and the combination of oil and coal to < 25% of the total heat input on a calendar quarter basis.
(g) Compliance is based on 30-day rolling average, per 40 CFR 60, Subpart Da.
(h) Subject to revision after testing pursuant to Specific Condition Nos. 23 and 24 in construction permit AC50-269980.
(i) Compliance based on a 12-month rolling average.

Table 2-5. Sulfur Analysis of Wood Waste, OKPLP, January 1997

Supplier	Sulfur Content (%S, dry)	Heating Value (Btu/lb, dry)	Equilivent SO2 Emissions (lb/MMBtu)
Supplier A	0.07	7,531	0.186
Supplier B	0.06	8,283	0.145
Supplier C	0.08	7,471	0.214
Supplier D	0.08	7,320	0.219
Supplier E	0.07	7,130	0.196
Supplier F	0.08	7,486	0.214
Supplier G	0.04	8,405	0.095
Supplier H	0.05	8,447	0.118
Supplier I	0.11	8,074	0.272
Supplier J	0.05	8,557	0.117
Supplier K	0.07	7,752	0.181
Supplier L	0.02	8,591	0.047
Supplier M	0.06	8,214	0.146
Supplier N	0.15	8,338	0.360
Supplier O	0.05	8,349	0.120
Supplier P	0.13	8,542	0.304
Supplier Q	0.07	6,994	0.200
Supplier R	0.12	8,213	0.292
Supplier S	0.03	7,999	0.075
Supplier T	0.11	7,987	0.275
Supplier U	0.13	7,560	0.344
Supplier V	0.11	8,042	0.274
Supplier W	0.17	7,670	0.443
Minimum	0.02	6,994	0.047
Maximum	0.17	8,591	0.443

Table 2-6. Stack Test Data for OkPLP and OsPLP Cogeneration Units Burning Wood Waste - SO2, CO, Pb

Boiler/Run	Sulfur Dioxide (SO2)				Carbon Monoxide (CO)				Lead (Pb)			
	Test Date	(ppmvd @ 7 % O2)	(lb/hr)	(lb/MMBtu)	Test Date	(ppmvd @ 7 % O2)	(lb/hr)	(lb/MMBtu)	Test Date	(mg/dscm @ 7 % O2)	(lb/hr)	(lb/MMBtu)
Okeelanta Unit A												
1	5/11/96	24.2	35.64	0.0514	5/10/96	268.5	166.38	0.249	5/10/96	0.0436	2.46E-02	3.48E-05
2	5/12/96	27.6	40.07	0.0586	5/10/96	181.4	118.89	0.168	5/11/96	0.0215	1.29E-02	1.71E-05
3	5/12/96	34.1	49.89	0.0723	5/10/96	168.7	110.59	0.157	5/11/96	0.0264	1.46E-02	2.10E-05
Average		28.6	41.87	0.0608		206.2	131.95	0.191		0.0305	1.74E-02	2.43E-05
4	5/29/96	29.2	44.97	0.0620	—	—	—	—	—	—	—	—
5	5/30/96	32.9	51.03	0.0700	—	—	—	—	—	—	—	—
6	5/30/96	30.9	50.60	0.0660	—	—	—	—	—	—	—	—
Average		29.6	44.87	0.0630		—	—	—		—	—	—
Okeelanta Unit B												
1	5/15/96	30.0	49.97	0.0691	5/14/96	198.5	138.33	0.183	5/15/96	0.0163	9.13E-03	1.30E-05
2	5/16/96	36.8	63.92	0.0862	5/14/96	218.9	152.84	0.203	5/15/96	0.2505	8.75E-03	1.29E-05
3	5/16/96	37.5	59.41	0.0856	5/14/96	168.2	116.11	0.156	5/15/96	0.2159	7.57E-03	1.11E-05
Average		34.7	57.77	0.0803		195.2	135.76	0.181		0.1609	8.48E-03	1.23E-05
Okeelanta Unit C												
1	6/3/96	19.7	31.13	0.0470	5/22/96	172.9	112.37	0.181	5/22/96	0.0274	1.63E-02	2.46E-05
2	6/3/96	9.7	15.78	0.0240	5/22/96	194.6	129.74	0.203	5/23/96	0.0283	1.59E-02	2.54E-05
3	6/3/96	18.7	28.81	0.0447	5/22/96	214.1	139.00	0.224	5/23/96	0.0368	2.05E-02	3.30E-05
Average		16.1	25.24	0.039		193.8	127.04	0.203		0.0308	1.76E-02	2.77E-05
Osceola Unit A												
A -1	12/15/96	17.3	26.5	0.038	12/14/96	208.3	144.4	0.22	12/15/96	0.0780	4.77E-02	7.04E-05
A -2	12/15/96	14.4	21.5	0.032	12/14/96	171.0	104.4	0.18	12/15/96	0.0644	3.69E-02	5.82E-05
A -3	12/15/96	4.6	7.3	0.010	12/14/96	203.8	134.9	0.21	12/15/96	0.0635	3.60E-02	5.74E-05
Average		12.1	18.4	0.027		194.4	127.9	0.20		0.0686	4.02E-02	6.20E-05
Osceola Unit B												
B -1	12/18/96	4.1	6.4	0.009	12/18/96	100.7	70.0	0.11	12/17/96	0.116	6.93E-02	1.05E-04
B -2	12/18/96	23.1	36.9	0.056	12/18/96	152.4	103.3	0.16	12/18/96	0.132	7.72E-02	1.22E-04
B -3	12/18/96	1.6	2.4	0.004	12/18/96	131.4	89.6	0.14	12/18/96	0.197	1.23E-01	1.81E-04
Average		9.6	15.2	0.023		128.1	87.6	0.14		0.148	8.98E-02	1.36E-04
Compliance Test Minimum		9.6	15.2	0.023		128.1	87.6	0.14		0.031	8.48E-03	1.23E-05
Compliance Test Average		21.8	33.9	0.049		183.5	122.1	0.18		0.088	3.47E-02	5.25E-05
Compliance Test Maximum		34.7	57.8	0.080		206.2	135.8	0.20		0.161	8.98E-02	1.36E-04
Standard Deviation				0.023				0.027				5.02E-05
t-statistic				2.105				2.132				2.132
95% Upper Confidence Limit				0.097				0.242				1.60E-04
Permit Limit				0.100				0.350				2.5E-5 Okeelanta 2.7E-6 Osceola

Table 2-7. Summary of CEMS Data for SO2, OkPLP, 1997

Boiler	Month	No. of Hours	Daily Average SO2 Emissions (lb/MMBtu)		
			Min.	Avg.	Max.
A	January	408	0.0470	0.0494	0.0510
	February	320	0.0170	0.0347	0.0520
	March (a)	23	0.0350	0.0350	0.0350
B	January	523	0.0180	0.0497	0.0780
	February	522	0.0110	0.0308	0.0550
	March	322	0.0180	0.0412	0.0620
C	January	384	0.0590	0.0601	0.0620
	February	434	0.0150	0.0280	0.0500
	March	575	0.0220	0.0424	0.0740
	Total hours =	3,511			
	Minimum =		0.0110		
	Average =			0.0419	
	Maximum =				0.0780

(a) Average consists of only one set of data.

Table 2-8. Mercury and Lead Content (mg/kg wet) of Wood Waste Recieved at Okeelanta Power Limited Partnership

Test Date		Lead (mg/kg)	Mercury (mg/kg)	Test Date		Lead (mg/kg)	Mercury (mg/kg)
07/15/96		4.2	0.065 (a)	09/16/96		5.4	0.029 (a)
07/16/96		4.1	0.060 (a)	09/23/96		28.0	0.066
07/21/96	(b)	6.9	0.062 (c)	10/05/96		3.5	0.029 (a)
07/25/96		11.0	0.260	11/25/96		3.9	0.025 (a)
07/29/96		10.0	0.160	12/02/96		4.7	0.029 (a)
07/29/96		6.3	0.025 (a)	12/09/96		5.1	0.091
07/31/96		4.0	0.090	12/13/96		2.3	0.029 (a)
08/5/96		2.0	0.025 (a)	12/17/96		18.0	0.029 (a)
08/7/96		0.5 (a)	0.025 (a)	12/18/96		22.0	0.087
08/9/96		4.7	0.025 (a)	12/20/96		5.0 (a)	0.025 (a)
08/12/96		0.5 (a)	0.200	01/14/97		3.2	0.025 (a)
08/15/96		4.0	0.025 (a)	01/20/97		5.4	1.000
08/16/96	(b)		0.530	01/22/97		16.0	0.025 (a)
08/20/96	(b)	7.7	0.041 (c)	01/24/97		7.8	0.062
08/21/96	(b)	37.8	0.078 (c)	01/28/97		350.0	0.050 (a)
08/23/96		16.0	0.029 (a)	01/29/97	(b)	3.1	0.038
08/27/96		2.8	0.029 (a)	02/03/97		2.8	0.025
08/29/96		8.0	0.029 (a)	02/05/97		0.5 (a)	0.050 (a)
09/04/96	(b)	16.5	0.045 (c)	02/07/97		1.4	0.050 (a)
09/06/96		9.5	0.029 (a)				
09/11/96		7.2	0.029 (a)	Minimum		0.5	0.025
09/13/96		5.9	0.250	Average		7.9	0.095
				Maximum		37.8	1.000

Note:
(a) Value represents 50% of detection limit
(b) Value is an average of multiple analysis on the given day.
(c) Value includes one analysis that represents 50% of detection limit.

Table 2-9. Mercury Stack Test Data for OkPLP and OsPLP Burning Wood Waste

Boiler/Run	Test Date	Mercury (Hg) (mg/dscm @ 7 % O2)	(lb/hr)	(lb/MMBtu)
Okeelanta Unit A				
1	5/11/96	1.86E-03	1.04E-03	1.48E-06
2	5/11/96	9.55E-04	5.13E-04	7.62E-07
3	5/11/96	8.59E-04	4.69E-04	6.84E-07
Average		1.22E-03	6.74E-04	9.75E-07
Okeelanta Unit B				
1	5/14/96	1.26E-03	6.95E-04	1.00E-06
2	5/14/96	1.21E-03	6.75E-04	9.65E-07
3	5/14/96	1.13E-03	6.39E-04	8.97E-07
Average		1.20E-03	6.70E-04	9.54E-07
1	12/09/96	2.63E-03	1.38E-03	2.09E-06
2	12/09/96	2.52E-03	1.34E-03	2.00E-06
3	12/10/96	2.98E-03	1.54E-03	2.38E-06
Average		2.71E-03	1.42E-03	2.16E-06
4	12/10/96	1.84E-03	1.08E-03	1.46E-06
5	12/10/96	1.84E-03	1.04E-03	1.46E-06
6	12/10/96	1.66E-03	9.90E-04	1.32E-06
Average		1.78E-03	1.04E-03	1.41E-06
7	12/11/96	1.94E-03	1.03E-03	1.54E-06
8	12/12/96	2.46E-03	1.35E-03	1.95E-06
9	12/12/96	2.51E-03	1.24E-03	1.99E-06
Average		2.30E-03	1.21E-03	1.83E-06
Okeelanta Unit C				
1	5/23/96	2.21E-03	1.30E-03	1.98E-06
2	5/23/96	2.23E-03	1.24E-03	1.90E-06
3	5/23/96	1.25E-03	7.13E-04	1.12E-06
Average		1.89E-03	1.09E-03	1.66E-06
2	12/13/96	3.43E-03	1.95E-03	2.72E-06
3	12/13/96	2.85E-03	1.63E-03	2.26E-06
4	12/13/96	3.31E-03	1.84E-03	2.63E-06
Average		3.20E-03	1.81E-03	2.54E-06
5	12/14/96	2.46E-03	1.37E-03	1.96E-06
6	12/14/96	2.29E-03	1.25E-03	1.82E-06
7	12/14/96	2.32E-03	1.28E-03	1.85E-06
Average		2.36E-03	1.30E-03	1.88E-06
8	12/15/96	2.18E-03	1.24E-03	1.74E-06
9	12/15/96	2.37E-03	1.25E-03	1.88E-06
10	12/15/96	1.85E-03	1.01E-03	1.48E-06
Average		2.14E-03	1.17E-03	1.70E-06
Osceola Unit A				
A -1	12/15/96	3.12E-03	1.91E-03	2.82E-06
A -2	12/15/96	3.22E-03	1.84E-03	2.91E-06
A -3	12/15/96	2.00E-03	1.13E-03	1.81E-06
Average		2.78E-03	1.63E-03	2.51E-06
Osceola Unit B				
B -1	12/17/96	3.33E-03	1.20E-03	3.02E-06
B -2	12/18/96	3.69E-03	2.15E-03	3.39E-06
B -3	12/18/96	3.59E-03	2.24E-03	3.29E-06
Average		3.54E-03	1.86E-03	3.23E-06
Compliance Test Minimum		1.20E-03	6.70E-04	9.54E-07
Compliance Test Average		2.28E-03	1.26E-03	1.90E-06
Compliance Test Maximum		3.54E-03	1.86E-03	3.23E-06
Standard Deviation				6.87E-07
t-statistic				1.812
95% Upper Confidence Limit				3.14E-06
Permit Limit				2.9E-7

Table 2-10. Calculated Mercury Removal Efficiency at OkPLP

Test Date	Carbon Injection Setting(a) (Hertz)	Run	Run Time (hrs)	Fuel Usage (tons - wet)	Fuel Analysis			Hg Content (lbs)	Hg Stack Emissions		Calculated Hg Removal Efficiency
					Hg Conc. (mg/kg,dry)	Moisture Content (%)	Hg Conc. (mg/kg,wet)		(lbs/hr)	(lbs)	
Boiler B											
12/09/96	15	1	2.10	124.36	0.230	26	0.170	0.0423	1.38E-03	2.90E-03	93.15%
12/09/96	15	2	2.05	100.71	0.064	36	0.041	0.0083	1.34E-03	2.75E-03	66.70%
12/10/96	15	3	2.07	115.37	0.080	29	0.057	0.0131	1.54E-03	3.18E-03	75.72%
12/10/96	30	4	2.07	128.05	0.075	34	0.050	0.0127	1.08E-03	2.23E-03	82.39%
12/10/96	30	5	2.22	123.50	0.015 (b)	25	0.011	0.0028	1.04E-03	2.31E-03	17.04%
12/10/96	30	6	2.05	121.76	0.049	30	0.034	0.0084	9.90E-04	2.03E-03	75.70%
12/11/96	45	7	2.03	104.48	0.043	28	0.031	0.0065	1.03E-03	2.09E-03	67.63%
12/12/96	45	8	2.03	100.24	0.055	26	0.041	0.0082	1.35E-03	2.75E-03	66.36%
12/12/96	45	9	2.03	99.54	0.066	28	0.048	0.0095	1.24E-03	2.52E-03	73.35%
										Average =	68.67%

(a) Hertz settings represent approximately the following:
15 Hertz - 25% of max. injection rate or 7 lb/hr
30 Hertz - 50% of max. injection rate or 16 lb/hr
45 Hertz - 75% of max. injection rate or 23 lb/hr
(b) Below detectable level. Value represents one-half the detectable level.

Table 2-11. Proposed Changes to Emission Limits at Osceola Power

Regulated Pollutant	Current Limit		Proposed Limit	
	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr
Nitrogen Oxide-Annual				
- Bagasse	0.12	88.2	0.15	114.0
- Woodwaste	0.12	88.2	0.15	114.0
- Fuel Oil	0.12	72.0	0.15	90.0
- Coal	0.15	79.5	0.17	90.1
- TDF	- -	- -	0.17	62.9
Sulfur Dioxide-Annual				
- Bagasse	0.02	- -	0.02	- -
- Woodwaste	0.02	- -	0.05	- -
Carbon Monoxide - Biomass				
- 8-hour	0.35	266.0	- -	- -
- 24-hour	- -	- -	0.35	266.0
Carbon Monoxide - No. 2 Fuel Oil/Coal/TDF				
- 8-hour	0.2	- -	- -	- -
- 24-hour	- -	- -	0.35	- -
Lead (Pb)				
- Bagasse	2.7×10^{-6}	0.0021	2.7×10^{-6}	0.0021
- Woodwaste	2.7×10^{-6}	0.0021	1.6×10^{-4}	0.12
Mercury (Hg)				
- Bagasse	5.7×10^{-6}	0.0043	3.5×10^{-6}	0.0027
- Woodwaste	0.29×10^{-6}	0.00022	4.0×10^{-6}	0.0030

Table 2-12. Maximum Hourly Emissions per Boiler for the Osceola Power Cogeneration Facility.

Regulated Pollutant	Bagasse (per boiler)			Woodwaste (per boiler)			No. 2 Fuel Oil (per boiler)			Coal (per boiler)			Tire-Derived Fuel (per boiler)			25%TDF 75% Biomass	Total Both Boilers- Any Fuels
	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Maximum Emissions (lb/hr) (c)	Maximum Emissions (lb/hr)
Particulate (TSP)	0.03	760	22.8	0.03	760	22.8	0.03	600	18.0	0.03	530	15.9	0.03	370	11.1	22.8	22.8
Particulate (PM10)	0.03	760	22.8	0.03	760	22.8	0.03	600	18.0	0.03	530	15.9	0.03	370	11.1	22.8	22.8
Sulfur dioxide:																	
3-hour	--	--	--	--	--	--	--	--	--	1.2	530	636.0	--	--	--	--	636.0
24-hour	0.10	760	76.0	0.10	760	78.0	0.05	600	30.0	1.2	530	636.0	1.2	370	444.0	483.0	836.0
Nitrogen oxides (a)	0.15	760	114.0	0.15	760	114.0	0.15	600	90.0	0.17	530	90.1	0.17	370	62.9	121.4	121.4
Carbon monoxide (b)	0.35	760	266.0	0.35	760	266.0	0.35	600	210.0	0.35	530	185.5	0.35	370	129.5	266.0	266.0
VOC	0.06	760	45.6	0.04	760	30.4	0.03	600	18.0	0.03	530	15.9	0.04	370	14.8	30.4	45.6
Lead	2.7E-06	760	0.0021	1.6E-04	760	0.12	8.9E-07	600	0.0005	5.1E-06	530	0.0027	4.2E-05	370	0.016	0.0779	0.12
Mercury	3.5E-06	760	0.0027	4.0E-06	760	0.0030	2.4E-06	600	0.0014	8.4E-06	530	0.0045	6.5E-06	370	0.0024	0.0040	0.0045
Beryllium	--	--	--	--	--	--	3.5E-07	600	0.00021	5.9E-06	530	0.0031	4.5E-07	370	1.7E-04	1.67E-04	0.0031
Fluorides	--	--	--	--	--	--	6.3E-06	600	0.0038	0.024	530	12.7	6.5E-04	370	0.24	0.24	12.7
Sulfuric acid mist (b)	0.0049	760	3.72	0.0049	760	3.72	0.0025	600	1.50	0.010	530	5.3	0.010	370	3.70	5.61	5.6

Notes:
(a) 30-day rolling average.
(b) 24-hour average.
(c) Weight basis; 370 MMBtu/hr TDF and 390 MMBtu/hr biomass.

Table 2-13. Maximum Annual Emissions from all Boilers for the Osceola Power Cogeneration Facility.

Regulated Pollutant	Bagasse b			Woodwaste c			Alternate Fuel			Total
	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Annual Emissions (TPY)
100 % Biomass by Weight										
Particulate (TSP)	0.03	4.925	73.87	0.03	3.283	49.25	--	--	--	123.1 a
Particulate (PM10)	0.03	4.925	73.87	0.03	3.283	49.25	--	--	--	123.1 a
Sulfur dioxide	0.02	4.925	49.25	0.05	3.283	82.08	--	--	--	131.3
Nitrogen oxides	0.15	4.925	369.36	0.15	3.283	246.24	--	--	--	615.6
Carbon monoxide	0.35	4.925	861.84	0.35	3.283	574.56	--	--	--	1,436.4 a
VOCs	0.06	4.925	147.74	0.04	3.283	65.66	--	--	--	213.4 a
Lead	2.7E-06	4.925	0.007	1.6E-04	3.283	0.263	--	--	--	0.27 a
Mercury	3.5E-06	4.925	0.0086	4.0E-06	3.283	0.0066	--	--	--	0.0152
Beryllium	--	--	--	--	--	--	--	--	--	--
Fluorides	--	--	--	--	--	--	--	--	--	--
Sulfuric acid mist	0.00098	4.925	2.41	0.00098	3.283	1.61	--	--	--	4.02
75.1% Biomass / 24.9% Fuel Oil by Weight										
Particulate (TSP)	0.03	3.482	52.23	0.03	2.321	34.82	0.03	1.924	28.86	115.9
Particulate (PM10)	0.03	3.482	52.23	0.03	2.321	34.82	0.03	1.924	28.86	115.9
Sulfur dioxide	0.02	3.482	34.82	0.05	2.321	58.03	0.05	1.924	48.10	140.9
Nitrogen oxides	0.15	3.482	261.14	0.15	2.321	174.09	0.15	1.924	144.30	579.5
Carbon monoxide	0.35	3.482	609.32	0.35	2.321	406.21	0.35	1.924	336.70	1,352.2
VOCs	0.06	3.482	104.45	0.04	2.321	46.42	0.03	1.924	28.86	179.7
Lead	2.7E-06	3.482	0.0047	1.6E-04	2.321	0.1857	8.9E-07	1.924	0.0009	0.19
Mercury	3.5E-06	3.482	0.0061	4.0E-06	2.321	0.0046	2.4E-06	1.924	0.0023	0.0130
Beryllium	--	--	--	--	--	--	3.5E-07	1.924	0.00034	0.00034
Fluorides	--	--	--	--	--	--	6.27E-06	1.924	0.0060	0.0060
Sulfuric acid mist	0.00098	3.482	1.71	0.00098	2.321	1.14	0.0025	1.924	2.41	5.25
95.6% Biomass / 4.4% Coal										
Particulate (TSP)	0.03	4.657	69.85	0.03	3.104	46.57	0.03	0.3572	5.36	121.8
Particulate (PM10)	0.03	4.657	69.85	0.03	3.104	46.57	0.03	0.3572	5.36	121.8
Sulfur dioxide	0.02	4.657	46.57	0.05	3.104	77.61	1.2	0.3572	214.32	338.5
Nitrogen oxides	0.15	4.657	349.25	0.15	3.104	232.83	0.17	0.3572	30.36	612.4
Carbon monoxide	0.35	4.657	814.91	0.35	3.104	543.27	0.35	0.3572	62.51	1,420.7
VOCs	0.06	4.657	139.70	0.04	3.104	62.09	0.03	0.3572	5.36	207.1
Lead	2.7E-06	4.657	0.006	1.6E-04	3.104	0.248	5.1E-06	0.3572	0.0009	0.26
Mercury	3.5E-06	4.657	0.0081	4.0E-06	3.104	0.0062	8.4E-06	0.3572	0.0015	0.0159
Beryllium	--	--	--	--	--	--	5.9E-06	0.3572	0.0011	0.0011 a
Fluorides	--	--	--	--	--	--	0.024	0.3572	4.29	4.29 a
Sulfuric acid mist	0.00098	4.657	2.28	0.00098	3.104	1.52	0.010	0.3572	1.79	5.59 a
86.2% Biomass / 13.8% Tire-Derived Fuel										
Particulate (TSP)	0.03	4.245	63.68	0.03	2.830	42.45	0.03	1.133	17.00	123.1 a
Particulate (PM10)	0.03	4.245	63.68	0.03	2.830	42.45	0.03	1.133	17.00	123.1 a
Sulfur dioxide	0.02	4.245	42.45	0.05	2.830	70.75	0.40	1.133	226.60	339.8 a
Nitrogen oxides	0.15	4.245	318.38	0.15	2.830	212.25	0.17	1.133	96.31	626.9 a
Carbon monoxide	0.35	4.245	742.88	0.35	2.830	495.25	0.35	1.133	198.28	1,436.4
VOCs	0.06	4.245	127.35	0.04	2.830	56.60	0.04	1.133	22.66	206.6
Lead	2.7E-06	4.245	0.006	1.6E-04	2.830	0.226	4.2E-05	1.133	0.0238	0.26
Mercury	3.5E-06	4.245	0.0074	4.0E-06	2.830	0.0057	6.5E-06	1.133	0.0037	0.0168 a
Beryllium	--	--	--	--	--	--	4.5E-07	1.133	0.00025	0.00025
Fluorides	--	--	--	--	--	--	6.5E-04	1.133	0.37	0.37
Sulfuric acid mist	0.00098	4.245	2.08	0.00098	2.830	1.39	0.0034	1.133	1.93	5.39

Notes:

a Denotes maximum annual emissions for any fuel scenario.

b Represents 60% of total biomass heat input.

c Represents 40% of total biomass heat input.

Note: No emissions of total reduced sulfur, asbestos, or vinyl chloride are expected.

Table 2-14. Maximum Fuel Usage and Heat Input Rates per Boiler, Osceola Power Limited Partnership

Fuel	Heat Input	Heat Transfer Efficiency (%)	Heat Output	Fuel Firing Rate	
	Maximum Short-Term (per boiler)				
	(MMBtu/hr)		(MMBtu/hr)		
Biomass					
- Bagasse	760	68	517	178,824	lb/hr
- Wood Waste	760	68	517	138,182	lb/hr
No. 2 Fuel Oil	600	85	510	4,348	gal/hr
Coal	530	85	451	44,167	lb/hr
Tire-Derived Fuel	370	68	252	23,871	lb/hr
	Annual Average (per boiler)				
	(Btu/yr)		(Btu/yr)		
NORMAL OPERATIONS					
Biomass	6.658E+12	68	4.527E+12	783,247	TPY (a)
No. 2 Fuel Oil	0	85	0	0	gal/yr
Coal	0	85	0	0	TPY
Tire-Derived Fuel	0	68	0	0	TPY
TOTAL	6.658E+12		4.527E+12		
24.9% OIL FIRING					
Biomass	4.707E+12	68	3.201E+12	553,765	TPY
No. 2 Fuel Oil	1.561E+12	85	1.327E+12	11,309,008	gal/yr
Coal	0	85	0	0	TPY
Tire-Derived Fuel	0	68	0	0	TPY
TOTAL	6.268E+12		4.527E+12		
5.44% COAL FIRING					
Biomass	6.211E+12	68	4.223E+12	730,706	TPY
No. 2 Fuel Oil	0	85	0	0	gal/yr
Coal	3.572E+11	85	3.036E+11	14,883	TPY
Tire-Derived Fuel	0	68	0	0	TPY
TOTAL	6.568E+12		4.527E+12		
17.01% TIRE-DERIVED FUEL					
Biomass	5.525E+12	68	3.757E+12	502,273	TPY (b)
No. 2 Fuel Oil	0	85	0	0	gal/yr
Coal	0	85	0	0	TPY
Tire-Derived Fuel	1.133E+12	68	7.702E+11	36,537	TPY
TOTAL	6.658E+12		4.527E+12		

(a) Based on bagasse firing.
(b) Based on wood waste firing.

Notes: Total heat output required 4.527E+12 Btu/yr total both boilers.
Fuels may be burned in combination, not to exceed total heat outputs.
Based on fuel heating values as follows:
Bagasse - 4,250 Btu/lb
Wood Waste - 5,500 Btu/lb
No. 2 Fuel Oil - 138,000 Btu/gal
Coal - 12,000 Btu/lb
Tire-derived fuel - 15,500 Btu/lb

Table 2-15. Maximum Annual Emissions for Any Single Boiler at the Osceola Power Cogeneration Facility

Regulated Pollutant	Bagasse b			Woodwaste c			Alternate Fuel			Total
	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Annual Emissions (TPY)
					100 % Biomass					
Particulate (TSP)	0.03	3.995	59.92	0.03	2.663	39.95	--	--	--	99.9
Particulate (PM10)	0.03	3.995	59.92	0.03	2.663	39.95	--	--	--	99.9
Sulfur dioxide	0.02	3.995	39.95	0.05	2.663	66.58	--	--	--	106.5
Nitrogen oxides	0.15	3.995	299.61	0.15	2.663	199.74	--	--	--	499.4
Carbon monoxide	0.35	3.995	699.09	0.35	2.663	466.06	--	--	--	1,165.2 a
VOCs	0.06	3.995	119.84	0.04	2.663	53.26	--	--	--	173.1 a
Lead	2.7E-06	3.995	0.005	1.6E-04	2.663	0.21	--	--	--	0.22 a
Mercury	3.5E-06	3.995	0.0070	4.0E-06	2.663	0.0053	--	--	--	0.0123
Beryllium	--	--	--	--	--	--	--	--	--	--
Fluorides	--	--	--	--	--	--	--	--	--	--
Sulfuric acid mist	0.00098	3.995	1.96	0.00098	2.663	1.30	--	--	--	3.26
					75.1% Biomass / 24.9% Fuel Oil					
Particulate (TSP)	0.03	2.824	42.36	0.03	1.883	28.24	0.03	1.561	23.42	94.0
Particulate (PM10)	0.03	2.824	42.36	0.03	1.883	28.24	0.03	1.561	23.42	94.0
Sulfur dioxide	0.02	2.824	28.24	0.05	1.883	47.07	0.05	1.561	39.03	114.3
Nitrogen oxides	0.15	2.824	211.82	0.15	1.883	141.21	0.15	1.561	117.08	470.1
Carbon monoxide	0.35	2.824	494.24	0.35	1.883	329.49	0.35	1.561	273.18	1,096.9
VOCs	0.06	2.824	84.73	0.04	1.883	37.66	0.03	1.561	23.42	145.8
Lead	2.7E-06	2.824	0.004	1.6E-04	1.883	0.15	8.9E-07	1.561	0.0007	0.16
Mercury	3.5E-06	2.824	0.0049	4.0E-06	1.883	0.0038	2.4E-06	1.561	0.0019	0.0106
Beryllium	--	--	--	--	--	--	3.5E-07	1.561	0.00027	0.00027
Fluorides	--	--	--	--	--	--	6.27E-06	1.561	0.0049	0.0049
Sulfuric acid mist	0.00098	2.824	1.38	0.00098	1.883	0.92	0.0025	1.561	1.95	4.26
					94.56% Biomass / 5.44% Coal					
Particulate (TSP)	0.03	3.727	55.90	0.03	2.484	37.27	0.03	0.3572	5.36	98.5
Particulate (PM10)	0.03	3.727	55.90	0.03	2.484	37.27	0.03	0.3572	5.36	98.5
Sulfur dioxide	0.02	3.727	37.27	0.05	2.484	62.11	1.2	0.3572	214.32	313.7
Nitrogen oxides	0.15	3.727	279.50	0.15	2.484	186.33	0.17	0.3572	30.36	496.2
Carbon monoxide	0.35	3.727	652.16	0.35	2.484	434.77	0.35	0.3572	62.51	1,149.4
VOCs	0.06	3.727	111.80	0.04	2.484	49.69	0.03	0.3572	5.36	166.8
Lead	2.7E-06	3.727	0.005	1.6E-04	2.484	0.199	5.1E-06	0.3572	0.0009	0.20
Mercury	3.5E-06	3.727	0.007	4.0E-06	2.484	0.005	8.4E-06	0.3572	0.0015	0.0130
Beryllium	--	--	--	--	--	--	5.9E-06	0.3572	0.0011	0.0011 a
Fluorides	--	--	--	--	--	--	0.024	0.3572	4.29	4.29 a
Sulfuric acid mist	0.00098	3.727	1.83	0.00098	2.484	1.22	0.010	0.3572	1.79	4.83 a
					82.99% Biomass / 17.01% Tire-Derived Fuel					
Particulate (TSP)	0.03	3.315	49.73	0.03	2.210	33.15	0.03	1.133	17.00	99.9 a
Particulate (PM10)	0.03	3.315	49.73	0.03	2.210	33.15	0.03	1.133	17.00	99.9 a
Sulfur dioxide	0.02	3.315	33.15	0.05	2.210	55.25	0.40	1.133	226.6	315.0 a
Nitrogen oxides	0.15	3.315	248.63	0.15	2.210	165.75	0.17	1.133	96.31	510.7 a
Carbon monoxide	0.35	3.315	580.13	0.35	2.210	386.75	0.35	1.133	198.28	1,165.2 a
VOCs	0.06	3.315	99.45	0.04	2.210	44.20	0.04	1.133	22.66	166.3
Lead	2.7E-06	3.315	0.004	1.6E-04	2.210	0.18	4.2E-05	1.133	0.024	0.21
Mercury	3.5E-06	3.315	0.006	4.0E-06	2.210	0.0044	6.5E-06	1.133	0.0037	0.0139 a
Beryllium	--	--	--	--	--	--	4.5E-07	1.133	0.00025	0.00025
Fluorides	--	--	--	--	--	--	6.5E-04	1.133	0.37	0.37
Sulfuric acid mist	0.00098	3.315	1.62	0.00098	2.210	1.08	0.003	1.133	1.93	4.63

a Denotes maximum annual emissions for any fuel scenario.
b Represents 60% of total biomass heat.
c Represents 40% of total biomass heat input.

Note: Fuel input percentages are on a heat input basis.

Table 2-16. Maximum Hourly Emissions of Hazardous/ Toxic Air Pollutants for Osceola Power Cogeneration Facility (per boiler).

Hazardous Air Pollutant	Biomass			No. 2 Fuel Oil			Coal			Tire-Derived Fuel			25%TDF/ 75% Biomass^a (lb/hr)	Maximum Hourly Emissions For Any Fuel (lb/hr)	Maximum Hourly Total Both Boilers (lb/hr)
	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr	Hourly Emissions (lb/hr)			
Hazardous Air Pollutants															
Acetaldehyde	7.8E-04	760	0.59	--	600	--	--	530	--	--	370	--	0.30	0.59	1.19
Acetophenone	3.7E-06	760	0.00	--	600	--	--	530	--	--	370	--	0.0014	0.0028	0.0056
Acrolein	6.5E-05	760	0.0494	--	600	--	--	530	--	--	370	--	0.025	0.049	0.099
Antimony	UD	760	--	2.4E-07	600	1.4E-04	3.49E-05	530	0.018	6.45E-09	370	2.4E-06	2.39E-06	0.018	0.037
Arsenic	1.30E-04	760	0.0988	4.2E-08	600	2.5E-05	5.4E-06	530	0.0029	4.52E-06	370	1.7E-03	0.05	0.10	0.20
Benzene	1.3E-03	760	1.0	--	600	--	--	530	--	--	370	--	0.51	0.99	1.98
Beryllium	--	--	--	3.5E-07	600	2.1E-04	5.9E-06	530	3.1E-03	4.50E-07	370	1.67E-04	1.67E-04	0.0031	0.0063
Cadmium	8.4E-07	760	6.38E-04	1.1E-07	600	6.6E-05	4.3E-07	530	2.3E-04	3.87E-06	370	1.4E-03	0.0018	0.0018	0.0035
Carbon Disulfide	1.3E-04	760	0.0988	--	600	--	--	530	--	--	370	--	0.051	0.099	0.198
Carbon Tetrachloride	6.0E-06	760	4.6E-03	--	600	--	--	530	--	--	370	--	0.0023	0.0046	0.0091
Chlorine	9.2E-04	760	7.0E-01	--	600	--	--	530	--	--	370		0.36	0.70	1.40
Chloroform	4.7E-05	760	0.036	--	600	--	--	530	--	--	370	--	0.018	0.036	0.071
Chromium	1.58E-04	760	0.120	8.7E-07	600	4.0E-04	1.66E-05	530	0.0088	6.45E-06	370	0.0024	0.064	0.12	0.24
Chromium +6	3.17E-05	760	0.024	1.3E-07	600	7.8E-05	3.1E-06	530	0.0016	--	370	--	0.012	0.024	0.048
Cobalt	1.5E-07	760	1.14E-04	1.2E-05	600	0.0072	7.2E-05	530	0.038	3.23E-04	370	0.120	0.120	0.120	0.239
Cumene	1.8E-05	760	0.0137	--	600	--	--	530	--	--	370	--	0.0070	0.014	0.027
Di - n - butyl Phthalate	5.8E-05	760	0.044	--	600	--	--	530	--	--	370	--	0.023	0.044	0.088
Ethyl Benzene	3.9E-06	760	0.0030	--	600	--	--	530	--	--	370	--	0.0015	0.0030	0.0059
Formaldehyde	1.3E-03	760	0.99	4.05E-04	600	0.24	2.2E-04	530	0.12	4.05E-04	370	0.150	0.66	0.99	1.98
n Hexane	5.5E-04	760	0.418	--	600	--	--	530	--	--	370	--	0.21	0.42	0.84
Hydrogen Chloride	5.6E-04	760	0.43	6.37E-04	600	0.38	7.9E-02	530	41.87	9.61E-02	370	35.56	35.78	41.87	83.74
Lead - Bagasse	2.7E-06	760	0.0021	8.9E-07	600	0.0005	5.1E-06	530	0.0027	4.19E-05	370	0.0155	0.0779	0.1216	0.243
- Wood Waste	1.6E-04	760	0.122												
Manganese	9.5E-05	760	0.072	1.4E-07	600	8.4E-05	3.1E-07	530	1.6E-04	6.45E-04	370	0.24	0.28	0.28	0.55
Mercury - Bagasse	3.5E-06	760	0.0027	2.4E-06	600	0.0014	8.4E-06	530	0.0045	5.00E-06	370	0.0019	0.0034	0.0045	0.0089
-Wood Waste	4.0E-06	760	0.0030												
Methanol	1.5E-03	760	1.1400	--	600	--	--	530	--	--	370	--	0.59	1.14	2.28
Methyl Ethyl Ketone	1.2E-05	760	0.0091	--	600	--	--	530	--	--	370	--	0.0047	0.0091	0.0182
Methyl Isobutyl Ketone	8.6E-04	760	0.65	--	600	--	--	530	--	--	370	--	0.34	0.65	1.31
Methylene Chloride	1.5E-03	760	1.14	--	600	--	--	530	--	--	370	--	0.59	1.14	2.28
Napthalene	5.9E-04	760	0.45	--	600	--	--	530	--	--	370	--	0.23	0.45	0.90
Nickel	6.3E-06	760	0.005	1.70E-06	600	1.0E-03	1.0E-05	530	0.0053	3.87E-05	370	0.0143	0.0168	0.0168	0.0336
Phenols	4.1E-05	760	0.0312	--	600	--	--	530	--	--	370	--	0.016	0.031	0.062
Phosphorus	1.6E-06	760	0.0012	5.81E-05	600	0.035	8.6E-04	530	0.46	--	370	--	6.24E-04	0.46	0.91
POM	2.2E-07	760	1.67E-04	8.4E-06	600	0.0050	--	530	--	--	370	--	8.58E-05	0.0050	0.010
Selenium	3.8E-06	760	0.0029	3.8E-07	600	2.3E-04	5.34E-05	530	0.028	6.77E-05	370	0.025	0.027	0.028	0.057
Styrene	1.5E-05	760	0.0114	--	600	--	--	530	--	--	370	--	0.0059	0.011	0.023
2, 3, 7, 8-TCDD(dioxin	6.0E-12	760	4.56E-09	--	600	--	--	530	--	--	370	--	2.3E-09	4.6E-09	9.1E-09
Toluene	9.0E-05	760	0.068	--	600	--	--	530	--	--	370	--	0.035	0.068	0.137
1, 1, 1 Trichloroethane	1.7E-04	760	0.13	--	600	--	--	530	--	--	370	--	0.066	0.13	0.26
Trichloroethylene	7.6E-06	760	0.006	--	600	--	--	530	--	--	370	--	0.0030	0.0058	0.0116
m&p Xylene	7.8E-06	760	0.0059	--	600	--	--	530	--	--	370	--	0.0030	0.0059	0.0119
o Xylene	2.6E-06	760	0.0020	--	600	--	--	530	--	--	370	--	0.0010	0.0020	0.0040
Total HAPs =			8.46			0.68			42.56			36.13	40.47		
112 (r) (non-HAPs)															
Ammonia	4.80E-02	760	36.48	1.48E-02	600	8.88	4.8E-02	530	25.44	4.80E-02	370	17.76	36.48	36.48	72.96
Bromine	4.59E-05	760	0.035	6.97E-07	600	4.2E-04	7.9E-04	530	0.42	--	370	--	0.018	0.42	0.84
Flourine	--	--	--	8.27E-06	600	0.0038	0.024	530	12.72	6.45E-04	370	0.24	0.24	12.72	25.44
Sulfuric acid	0.0049	760	3.72	2.50E-03	600	1.50	0.010	530	5.30	0.010	370	3.70	5.61	5.61	11.22
Other Air Toxics															
Acetone	3.80E-04	760	0.289	--	600	--	--	530	--	--	370	--	0.148	0.289	0.578
Barium	5.20E-06	760	0.0040	6.69E-07	600	4.0E-04	7.44E-05	530	0.039	7.74E-06	370	0.0029	0.005	0.039	0.079
Benzo(a)anthracene	7.53E-07	760	5.72E-04	--	600	--	--	530	--	--	370	--	2.94E-04	5.72E-04	0.0011
Benzo(a)pyrene	3.53E-08	760	2.68E-05	--	600	--	--	530	--	--	370	--	1.38E-05	2.68E-05	5.37E-05
Chrysene	3.53E-05	760	0.027	--	600	--	--	530	--	--	370	--	0.014	0.027	0.054
Copper	1.48E-04	760	0.11	4.20E-05	600	0.025	--	530	--	6.13E-04	370	0.23	0.28	0.28	0.57
Indium	1.27E-04	760	0.097	--	600	--	--	530	--	--	370	--	0.050	0.097	0.193
Iodine	2.12E-06	760	0.0016	--	600	--	--	530	--	--	370	--	0.0008	0.0016	0.0032
Isopropanol	9.20E-03	760	6.99	--	600	--	--	530	--	--	370	--	3.59	6.99	13.98
Molybdenum	2.24E-07	760	1.7E-04	4.88E-07	600	2.9E-04	8.83E-06	530	0.0047	4.52E-05	370	0.0167	0.0168	0.0168	0.034
PAH	5.90E-10	760	4.5E-07	--	600	--	--	530	--	--	370	--	2.30E-07	4.48E-07	8.97E-07
Silver	1.40E-06	780	0.0011	--	600	--	--	530	--	--	370	--	0.0005	0.0011	0.0021
Thallium	UD	760	--	--	600	--	--	530	--	--	370	--	--	--	--
Tin	3.65E-08	760	2.8E-05	3.30E-06	600	0.0020	8.83E-06	530	0.0047	6.45E-09	370	2.4E-06	1.66E-05	0.0047	0.0094
Tungsten	1.29E-08	760	9.8E-06	--	600	--	--	530	--	--	370	--	5.03E-06	9.80E-06	1.96E-05
Uranium	--	760	--	--	600	--	--	530	--	2.58E-08	370	9.5E-06	9.5E-06	9.5E-06	1.9E-05
Vanadium	1.41E-07	760	1.1E-04	--	600	--	--	530	--	6.45E-07	370	2.4E-04	2.9E-04	2.9E-04	5.9E-04
Yttrium	6.59E-08	760	5.0E-05	--	600	--	--	530	--	--	370	--	2.6E-05	5.0E-05	1.0E-04
Zinc	4.24E-04	760	0.32	6.69E-06	600	0.0040	3.49E-04	530	0.18	9.81E-03	370	3.63	3.80	3.80	7.59
Zirconium	4.12E-07	760	3.13E-04	--	600	--	--	530	--	--	370	--	1.6E-04	3.1E-04	6.3E-04

Note: UD = undetectable levels in gas stream.
^a Weight basis.

Table 2-17. Maximum Annual Emissions of Harzardous/Toxic Air Pollutants for Osceola Power (total all boilers)

Pollutant	Biomass: Emission Factor (lb/MMBtu)	Biomass: Activity Factor (E12 Btu/yr)	Biomass: Annual Emissions (TPY)	Alternate Fuel: Emission Factor (lb/MMBtu)	Alternate Fuel: Activity Factor (E12 Btu/yr)	Alternate Fuel: Annual Emissions (TPY)	Annual Emissions (TPY)
			100% Biomass				
Hazardous Air Pollutants							
Acetaldehyde	7.80E-04	8.208	3.20	–	–	–	3.20 a
Acetophenone	3.70E-06	8.208	0.015	–	–	–	0.015 a
Acrolein	6.50E-05	8.208	0.27	–	–	–	0.27 a
Antimony	UD	8.208	–	–	–	–	–
Arsenic	6.79E-05	8.208	0.28	–	–	–	0.28 a
Benzene	1.30E-03	8.208	5.34	–	–	–	5.34 a
Beryllium	–	8.208	–	–	–	–	–
Cadmium	8.40E-07	8.208	0.0034	–	–	–	0.0034
Carbon Disulfide	1.30E-04	8.208	0.53	–	–	–	0.53 a
Carbon Tetrachloride	6.00E-06	8.208	0.025	–	–	–	0.025 a
Chlorine	9.20E-04	8.208	3.78	–	–	–	3.78 a
Chloroform	4.70E-05	8.208	0.19	–	–	–	0.19 a
Chromium	8.27E-05	8.208	0.34	–	–	–	0.34 a
Chromium +6	1.65E-05	8.208	0.068	–	–	–	0.068 a
Cobalt	1.50E-07	8.208	6.2E-04	–	–	–	6.2E-04
Cumene	1.80E-05	8.208	0.07	–	–	–	0.07 a
Di - n - butyl Phthalate	5.80E-05	8.208	0.24	–	–	–	0.24 a
Ethyl Benzene	3.90E-06	8.208	0.016	–	–	–	0.016 a
Formaldehyde	1.30E-03	8.208	5.34	–	–	–	5.34 a
n Hexane	5.50E-04	8.208	2.26	–	–	–	2.26 a
Hydrogen Chloride	5.60E-04	8.208	2.30	–	–	–	2.30
Lead - Bagasse	2.70E-06	4.925	0.0066	–	–	–	0.269 a
-Wood Waste	1.60E-04	3.283	0.2626				
Manganese	9.50E-05	8.208	0.39	–	–	–	0.39
Mercury - Bagasse	3.50E-06	4.925	0.0086	–	–	–	0.015
-Wood Waste	4.00E-06	3.283	0.0066	–	–	–	
Methanol	1.50E-03	8.208	6.16	–	–	–	6.16 a
Methyl Ethyl Ketone	1.20E-05	8.208	0.049	–	–	–	0.049 a
Methyl Isobutyl Ketone	8.60E-04	8.208	3.53	–	–	–	3.53 a
Methylene Chloride	1.50E-03	8.208	6.16	–	–	–	6.16 a
Napthalene	5.90E-04	8.208	2.42	–	–	–	2.42 a
Nickel	6.30E-06	8.208	0.026	–	–	–	0.026
Phenols	4.10E-05	8.208	0.17	–	–	–	0.17 a
Phosphorus	1.60E-06	8.208	0.0066	–	–	–	0.0066
POM (Polycyclic Org. Matter)	2.20E-07	8.208	0.0009	–	–	–	0.0009
Selenium	3.80E-06	8.208	0.016	–	–	–	0.016
Styrene	1.50E-05	8.208	0.062	–	–	–	0.062 a
2, 3, 7, 8 -TCDD (dioxin)	6.00E-12	8.208	2.5E-08	–	–	–	2.5E-08 a
Toluene	9.00E-05	8.208	0.37	–	–	–	0.37 a
1, 1, 1 Trichloroethane	1.70E-04	8.208	0.70	–	–	–	0.70 a
Trichloroethylene	7.60E-06	8.208	0.031	–	–	–	0.031 a
m&p Xylene	7.80E-06	8.208	0.032	–	–	–	0.032 a
o Xylene	2.60E-06	8.208	0.011	–	–	–	0.011 a
Total HAPs							44.659
112 (r) (non-HAPs)							
Ammonia	4.80E-02	8.208	196.99	–	–	–	196.99 a
Bromine	4.59E-05	8.208	0.19	–	–	–	0.19
Flourine	–	8.208	–	–	–	–	–
Sulfuric acid	9.80E-04	8.208	4.02	–	–	–	4.02
Other Air Toxics							
Acetone	3.80E-04	8.208	1.56	–	–	–	1.56 a
Barium	5.20E-06	8.208	0.02	–	–	–	0.02
Benzo(a)anthracene	7.53E-07	8.208	0.0031	–	–	–	0.0031
Benzo(a)pyrene	3.53E-08	8.208	1.45E-04	–	–	–	1.45E-04 a
Chrysene	3.53E-05	8.208	0.14	–	–	–	0.14 a
Copper	8.02E-05	8.208	0.33	–	–	–	0.33
Indium	1.27E-04	8.208	0.52	–	–	–	0.52 a
Iodine	2.12E-06	8.208	0.0087	–	–	–	0.0087 a
Isopropanol	9.20E-03	8.208	37.76	–	–	–	37.76 a
Molybdenum	2.24E-07	8.208	9.19E-04	–	–	–	9.19E-04
PAH	5.90E-10	8.208	2.42E-06	–	–	–	2.42E-06 a
Silver	1.40E-06	8.208	0.0057	–	–	–	0.0057 a
Thallium	UD	8.208	–	–	–	–	–
Tin	3.65E-08	8.208	1.5E-04	–	–	–	1.5E-04
Tungsten	1.29E-08	8.208	5.3E-05	–	–	–	5.3E-05 a
Uranium	–	8.208	–	–	–	–	–
Vanadium	1.41E-07	8.208	5.8E-04	–	–	–	5.8E-04
Yttrium	6.59E-08	8.208	2.7E-04	–	–	–	2.7E-04 a
Zinc	4.24E-04	8.208	1.74	–	–	–	1.74
Zirconium	4.12E-07	8.208	0.0017	–	–	–	0.0017 a

Table 2-17. Maximum Annual Emissions of Harzardous/Toxic Air Pollutants for Osceola Power (total all boilers)

	Biomass			Alternate Fuel			
Pollutant	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Annual Emissions (TPY)
			75.1% Biomass / 24.9% Fuel Oil				
Hazardous Air Pollutants							
Acetaldehyde	7.80E-04	5.803	2.26	–	1.924	–	2.26
Acetophenone	3.70E-06	5.803	0.011	–	1.924	–	0.011
Acrolein	6.50E-05	5.803	0.19	–	1.924	–	0.19
Antimony	UD	5.803	–	2.40E-07	1.924	0.0002	0.0002
Arsenic	6.79E-05	5.803	0.20	4.20E-08	1.924	4.0E-05	0.20
Benzene	1.30E-03	5.803	3.77	–	1.924	–	3.77
Beryllium	–	5.803	–	3.50E-07	1.924	3.4E-04	0.0003 a
Cadmium	8.40E-07	5.803	0.0024	1.10E-07	1.924	1.1E-04	0.0025
Carbon Disulfide	1.30E-04	5.803	0.38	–	1.924	–	0.38
Carbon Tetrachloride	6.00E-06	5.803	0.017	–	1.924	–	0.017
Chlorine	9.20E-04	5.803	2.67	–	1.924	–	2.67
Chloroform	4.70E-05	5.803	0.14	–	1.924	–	0.14
Chromium	8.27E-05	5.803	0.24	6.70E-07	1.924	0.0006	0.24
Chromium +6	1.65E-05	5.803	0.048	1.30E-07	1.924	1.3E-04	0.048
Cobalt	1.50E-07	5.803	4.4E-04	1.20E-05	1.924	0.012	0.012
Cumene	1.80E-05	5.803	0.052	–	1.924	–	0.052
Di - n - butyl Phthalate	5.80E-05	5.803	0.17	–	1.924	–	0.17
Ethyl Benzene	3.90E-06	5.803	0.011	–	1.924	–	0.011
Formaldehyde	1.30E-03	5.803	3.77	4.05E-04	1.924	0.39	4.16
n Hexane	5.50E-04	5.803	1.60	–	1.924	–	1.60
Hydrogen Chloride	5.60E-04	5.803	1.62	6.37E-04	1.924	0.61	2.24
Lead - Bagasse	2.70E-06	3.482	0.0047	2.70E-06	1.924	0.0026	0.193
-Wood Waste	1.60E-04	2.321	0.186				
Manganese	9.50E-05	5.803	0.28	1.40E-07	1.924	1.3E-04	0.28
Mercury - Bagasse	3.50E-06	3.482	0.0061	2.40E-06	1.924	0.0023	0.013
-Wood Waste	4.00E-06	2.321	0.0046				
Methanol	1.50E-03	5.803	4.35	–	1.924	–	4.35
Methyl Ethyl Ketone	1.20E-05	5.803	0.035	–	1.924	–	0.035
Methyl Isobutyl Ketone	8.60E-04	5.803	2.50	–	1.924	–	2.50
Methylene Chloride	1.50E-03	5.803	4.35	–	1.924	–	4.35
Napthalene	5.90E-04	5.803	1.71	–	1.924	–	1.71
Nickel	6.30E-06	5.803	0.018	1.70E-06	1.924	0.0016	0.020
Phenols	4.10E-05	5.803	0.12	–	1.924	–	0.12
Phosphorus	1.60E-06	5.803	0.0046	5.81E-05	1.924	0.056	0.061
POM (Polycyclic Org. Matter)	2.20E-07	5.803	0.0006	8.40E-06	1.924	0.008	0.009 a
Selenium	3.80E-06	5.803	0.011	3.80E-07	1.924	3.7E-04	0.011
Styrene	1.50E-05	5.803	0.044	–	1.924	–	0.044
2, 3, 7, 8 -TCDD (dioxin)	6.00E-12	5.803	1.7E-08	–	1.924	–	1.7E-08
Toluene	9.00E-05	5.803	0.26	–	1.924	–	0.26
1, 1, 1 Trichloroethane	1.70E-04	5.803	0.49	–	1.924	–	0.49
Trichloroethylene	7.60E-06	5.803	0.022	–	1.924	–	0.022
m & p Xylene	7.80E-06	5.803	0.023	–	1.924	–	0.023
o Xylene	2.60E-06	5.803	0.008	–	1.924	–	0.008
Total HAPs							32.660
112 (r) (non-HAPs)							
Ammonia	4.80E-02	5.803	139.27	1.48E-02	1.924	14.24	153.51
Bromine	4.59E-05	5.803	0.13	6.97E-07	1.924	0.0007	0.13
Flourine	–	5.803	–	6.30E-06	1.924	0.0061	0.0061
Sulfuric acid	9.80E-04	5.803	2.84	2.50E-03	1.924	2.41	5.25
Other Air Toxics							
Acetone	3.80E-04	5.803	1.10	–	–	–	1.10
Barium	5.20E-06	5.803	0.02	6.69E-07	1.924	0.0006	0.02
Benzo(a)anthracene	7.53E-07	5.803	0.0022	4.20E-05	1.924	0.040	0.04 a
Benzo(a)pyrene	3.53E-08	5.803	1.02E-04	–	1.924	–	0.00
Chrysene	3.53E-05	5.803	0.10	–	1.924	–	0.10
Copper	8.02E-05	5.803	0.23	–	1.924	–	0.23
Indium	1.27E-04	5.803	0.37	–	1.924	–	0.37
Iodine	2.12E-06	5.803	0.0062	–	1.924	–	0.0062
Isopropanol	9.20E-03	5.803	26.69	–	1.924	–	26.69
Molybdenum	2.24E-07	5.803	6.50E-04	4.88E-07	1.924	4.7E-04	0.0011
PAH	5.90E-10	5.803	1.71E-06	–	1.924	–	1.71E-06
Silver	1.40E-06	5.803	0.0041	–	1.924	–	0.0041
Thallium	UD	5.803	–	–	1.924	–	–
Tin	3.65E-08	5.803	1.1E-04	3.30E-06	1.924	0.0032	0.0033 a
Tungsten	1.29E-08	5.803	3.7E-05	–	1.924	–	3.74E-05
Uranium	–	5.803	–	–	1.924	–	–
Vanadium	1.41E-07	5.803	4.1E-04	–	1.924	–	4.09E-04
Yttrium	6.59E-08	5.803	1.9E-04	–	1.924	–	1.91E-04
Zinc	4.24E-04	5.803	1.23	6.69E-06	1.924	0.006	1.24
Zirconium	4.12E-07	5.803	0.0012	–	1.924	–	0.0012

Table 2-17. Maximum Annual Emissions of Harzardous/Toxic Air Pollutants for Osceola Power (total all boilers)

	Biomass			Alternate Fuel			
Pollutant	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Annual Emissions (TPY)
			95.6% Biomass / 4.4% Coal				
Hazardous Air Pollutants							
Acetaldehyde	7.80E-04	7.761	3.03	--	0.3572	--	3.03
Acetophenone	3.70E-06	7.761	0.014	--	0.3572	--	0.014
Acrolein	6.50E-05	7.761	0.25	--	0.3572	--	0.25
Antimony	UD	7.761	--	3.49E-05	0.3572	0.006	0.006 a
Arsenic	6.79E-05	7.761	0.26	5.40E-06	0.3572	0.0010	0.26
Benzene	1.30E-03	7.761	5.04	--	0.3572	--	5.04
Beryllium	--	7.761	--	3.50E-07	0.3572	6.3E-05	6.3E-05
Cadmium	8.40E-07	7.761	0.0033	4.30E-07	0.3572	7.7E-05	0.0033
Carbon Disulfide	1.30E-04	7.761	0.50	--	0.3572	--	0.50
Carbon Tetrachloride	6.00E-06	7.761	0.023	--	0.3572	--	0.023
Chlorine	9.20E-04	7.761	3.57	--	0.3572	--	3.57
Chloroform	4.70E-05	7.761	0.18	--	0.3572	--	0.18
Chromium	8.27E-05	7.761	0.32	1.66E-05	0.3572	0.003	0.32
Chromium +6	1.65E-05	7.761	0.064	3.10E-06	0.3572	0.0006	0.065
Cobalt	1.50E-07	7.761	5.8E-04	7.20E-05	0.3572	0.013	0.013
Cumene	1.80E-05	7.761	0.070	--	0.3572	--	0.070
Di - n - butyl Phthalate	5.80E-05	7.761	0.23	--	0.3572	--	0.23
Ethyl Benzene	3.90E-06	7.761	0.015	--	0.3572	--	0.015
Formaldehyde	1.30E-03	7.761	5.04	2.20E-04	0.3572	0.04	5.08
n Hexane	5.50E-04	7.761	2.13	--	0.3572	--	2.13
Hydrogen Chloride	5.60E-04	7.761	2.17	7.90E-02	0.3572	14.11	16.28
Lead - Bagasse	2.70E-06	4.657	0.0063	5.10E-06	0.3572	--	0.255
-Wood Waste	1.60E-04	3.104	0.2483				
Manganese	9.50E-05	7.761	0.37	3.10E-07	0.3572	5.5E-05	0.37
Mercury - Bagasse	3.50E-06	4.657	0.008	8.40E-06	0.3572	0.0015	0.016
-Wood Waste	4.00E-06	3.104	0.0062				
Methanol	1.50E-03	7.761	5.82	--	0.3572	--	5.82
Methyl Ethyl Ketone	1.20E-05	7.761	0.047	--	0.3572	--	0.047
Methyl Isobutyl Ketone	8.60E-04	7.761	3.34	--	0.3572	--	3.34
Methylene Chloride	1.50E-03	7.761	5.82	--	0.3572	--	5.82
Napthalene	5.90E-04	7.761	2.29	--	0.3572	--	2.29
Nickel	6.30E-06	7.761	0.024	1.00E-05	0.3572	0.0018	0.026
Phenols	4.10E-05	7.761	0.16	--	0.3572	--	0.16
Phosphorus	1.60E-06	7.761	0.0062	8.60E-04	0.3572	0.15	0.160 a
POM (Polycyclic Org. Matter)	2.20E-07	7.761	0.0009	--	0.3572	--	0.0009
Selenium	3.80E-06	7.761	0.015	5.34E-05	0.3572	0.010	0.024
Styrene	1.50E-05	7.761	0.058	--	0.3572	--	0.058
2, 3, 7, 8 TCDD (dioxin)	6.00E-12	7.761	2.3E-08	--	0.3572	--	2.3E-08
Toluene	9.00E-05	7.761	0.35	--	0.3572	--	0.35
1, 1, 1 Trichloroethane	1.70E-04	7.761	0.66	--	0.3572	--	0.66
Trichloroethylene	7.60E-06	7.761	0.029	--	0.3572	--	0.029
m & p Xylene	7.80E-06	7.761	0.030	--	0.3572	--	0.030
o Xylene	2.60E-06	7.761	0.010	--	0.3572	--	0.010
Total HAPs							56.566
112 (r) (non-HAPs)							
Ammonia	4.80E-02	7.761	186.26	4.80E-02	0.3572	8.57	194.8
Bromine	4.59E-05	7.761	0.18	7.90E-04	0.3572	0.14	0.32 a
Flourine	--	7.761	--	2.40E-02	0.3572	4.29	4.29 a
Sulfuric acid	9.80E-04	7.761	3.80	0.010	0.3572	1.79	5.59 a
Other Air Toxics							
Acetone	3.80E-04	7.761	1.47	--	0.3572	--	1.47
Barium	5.20E-06	7.761	0.02	7.44E-05	0.3572	0.013	0.03 a
Benzo(a)anthracene	7.53E-07	7.761	2.92E-03	--	0.3572	--	2.92E-03
Benzo(a)pyrene	3.53E-08	7.761	1.37E-04	--	0.3572	--	1.37E-04
Chrysene	3.53E-05	7.761	0.14	--	0.3572	--	0.14
Copper	8.02E-05	7.761	0.31	--	0.3572	--	0.31
Indium	1.27E-04	7.761	0.49	--	0.3572	--	0.49
Iodine	2.12E-06	7.761	0.0082	--	0.3572	--	0.0082
Isopropanol	9.20E-03	7.761	35.70	--	0.3572	--	35.70
Molybdenum	2.24E-07	7.761	8.69E-04	8.83E-06	0.3572	0.0016	0.0024
PAH	5.90E-10	7.761	2.29E-06	--	0.3572	--	2.29E-06
Silver	1.40E-06	7.761	0.0054	--	0.3572	--	0.0054
Thallium	UD	7.761	--	--	0.3572	--	--
Tin	3.65E-08	7.761	1.4E-04	8.83E-06	0.3572	0.0016	0.0017
Tungsten	1.29E-08	7.761	5.0E-05	--	0.3572	--	5.01E-05
Uranium	--	7.761	--	--	0.3572	--	--
Vanadium	1.41E-07	7.761	5.5E-04	--	0.3572	--	5.47E-04
Yttrium	6.59E-08	7.761	2.6E-04	--	0.3572	--	2.56E-04
Zinc	4.24E-04	7.761	1.64	3.49E-04	0.3572	0.06	1.71
Zirconium	4.12E-07	7.761	0.0016	--	0.3572	--	0.0016

Table 2-17. Maximum Annual Emissions of Harzardous/Toxic Air Pollutants for Osceola Power (total all boilers)

	Biomass			Alternate Fuel			
Pollutant	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Annual Emissions (TPY)
			86.2% Biomass / 13.8% Tire-Derived Fuel				
Hazardous Air Pollutants							
Acetaldehyde	7.80E-04	7.075	2.76	--	1.133	--	2.76
Acetophenone	3.70E-06	7.075	0.013	--	1.133	--	0.013
Acrolein	6.50E-05	7.075	0.23	--	1.133	--	0.23
Antimony	UD	7.075	--	6.45E-09	1.133	3.7E-06	3.7E-06
Arsenic	6.79E-05	7.075	0.24	4.52E-06	1.133	0.003	0.24
Benzene	1.30E-03	7.075	4.60	--	1.133	--	4.599
Beryllium	--	7.075	--	--	1.133	--	--
Cadmium	8.40E-07	7.075	0.0030	3.87E-06	1.133	0.0022	0.0052 a
Carbon Disulfide	1.30E-04	7.075	0.46	--	1.133	--	0.46
Carbon Tetrachloride	6.00E-06	7.075	0.021	--	1.133	--	0.021
Chlorine	9.20E-04	7.075	3.25	--	1.133		3.25
Chloroform	4.70E-05	7.075	0.17	--	1.133	--	0.17
Chromium	8.27E-05	7.075	0.29	6.45E-06	1.133	0.0037	0.30
Chromium +6	1.65E-05	7.075	0.058	--	1.133	--	0.058
Cobalt	1.50E-07	7.075	5.3E-04	3.23E-04	1.133	0.18	0.18 a
Cumene	1.80E-05	7.075	0.064	--	1.133	--	0.064
Di - n - butyl Phthalate	5.80E-05	7.075	0.21	--	1.133	--	0.21
Ethyl Benzene	3.90E-06	7.075	0.014	--	1.133	--	0.014
Formaldehyde	1.30E-03	7.075	4.60	4.05E-04	1.133	0.23	4.83
n Hexane	5.50E-04	7.075	1.95	--	1.133	--	1.95
Hydrogen Chloride	5.60E-04	7.075	1.98	9.61E-02	1.133	54.4	56.4 a
Lead	2.70E-06	4.245	0.0057	4.20E-05	1.133	2.4E-02	0.256
	1.60E-04	2.830	0.226				
Manganese	9.50E-05	7.075	0.34	6.45E-04	1.133	0.37	0.70 a
Mercury - Bagasse	3.50E-06	4.245	0.007	6.50E-06	1.133	3.7E-03	0.0168 a
-Wood Waste	4.00E-06	2.830	0.0057				
Methanol	1.50E-03	7.075	5.31	--	1.133	--	5.31
Methyl Ethyl Ketone	1.20E-05	7.075	0.042	--	1.133	--	0.042
Methyl Isobutyl Ketone	8.60E-04	7.075	3.04	--	1.133	--	3.04
Methylene Chloride	1.50E-03	7.075	5.31	--	1.133	--	5.31
Napthalene	5.90E-04	7.075	2.09	--	1.133	--	2.09
Nickel	6.30E-06	7.075	0.022	3.87E-05	1.133	0.022	0.044 a
Phenols	4.10E-05	7.075	0.15	--	1.133	--	0.15
Phosphorus	1.60E-06	7.075	0.0057	--	1.133	--	0.0057
POM (Polycyclic Org. Matter)	2.20E-07	7.075	0.0008	--	1.133	--	0.0008
Selenium	3.80E-06	7.075	0.013	6.77E-05	1.133	0.04	0.05 a
Styrene	1.50E-05	7.075	0.053	--	1.133	--	0.053
2, 3, 7, 8 TCDD (dioxin)	6.00E-12	7.075	2.1E-08	--	1.133	--	2.1E-08
Toluene	9.00E-05	7.075	0.32	--	1.133	--	0.32
1, 1, 1 Trichloroethane	1.70E-04	7.075	0.60	--	1.133	--	0.60
Trichloroethylene	7.60E-06	7.075	0.027	--	1.133	--	0.027
m & p Xylene	7.80E-06	7.075	0.028	--	1.133	--	0.028
o Xylene	2.60E-06	7.075	0.009	--	1.133	--	0.009
Total HAPs							93.809
112 (r) (non-HAPs)							
Ammonia	1.48E-02	7.075	52.36	4.80E-02	1.133	27.19	79.5
Bromine	4.59E-05	7.075	0.16	--	1.133	--	0.16
Flourine	--	7.075	--	6.50E-03	1.133	3.6823	3.68
Sulfuric acid	9.80E-04	7.075	3.47	3.40E-03	1.133	1.9261	5.39
Other Air Toxics							
Acetone	3.80E-04	7.075	1.34	--	1.133	--	1.34
Barium	5.20E-06	7.075	0.02	7.74E-06	1.133	0.0044	0.02
Benzo(a)anthracene	7.53E-07	7.075	2.66E-03	--	1.133	--	2.66E-03
Benzo(a)pyrene	3.53E-08	7.075	1.25E-04	--	1.133	--	1.25E-04
Chrysene	3.53E-05	7.075	0.12	--	1.133	--	0.12
Copper	8.02E-05	7.075	0.28	6.15E-04	1.133	0.35	0.63 a
Indium	1.27E-04	7.075	0.45	--	1.133	--	0.45
Iodine	2.12E-06	7.075	0.0075	--	1.133	--	0.0075
Isopropanol	9.20E-03	7.075	32.55	--	1.133	--	32.55
Molybdenum	2.24E-07	7.075	7.92E-04	4.52E-05	1.133	0.026	0.026 a
PAH	5.90E-10	7.075	2.09E-06	--	1.133	--	2.09E-06
Silver	1.40E-06	7.075	0.0050	--	1.133	--	0.0050
Thallium	UD	7.075	--	--	1.133	--	--
Tin	3.65E-08	7.075	1.3E-04	6.45E-09	1.133	3.65E-06	1.3E-04
Tungsten	1.29E-08	7.075	4.6E-05	--	1.133	--	4.6E-05
Uranium	--	7.075	--	2.58E-08	1.133	1.46E-05	1.5E-05 a
Vanadium	1.41E-07	7.075	5.0E-04	6.45E-07	1.133	0.00037	8.6E-04 a
Yttrium	6.59E-08	7.075	2.3E-04	--	1.133	--	2.3E-04
Zinc	4.24E-04	7.075	1.50	9.81E-03	1.133	5.56	7.06 a
Zirconium	4.12E-07	7.075	0.0015	--	1.133	--	0.0015

a Denotes maximum annual emissions for any fuel scenario.

Note: UD = undetectable levels in gas stream.

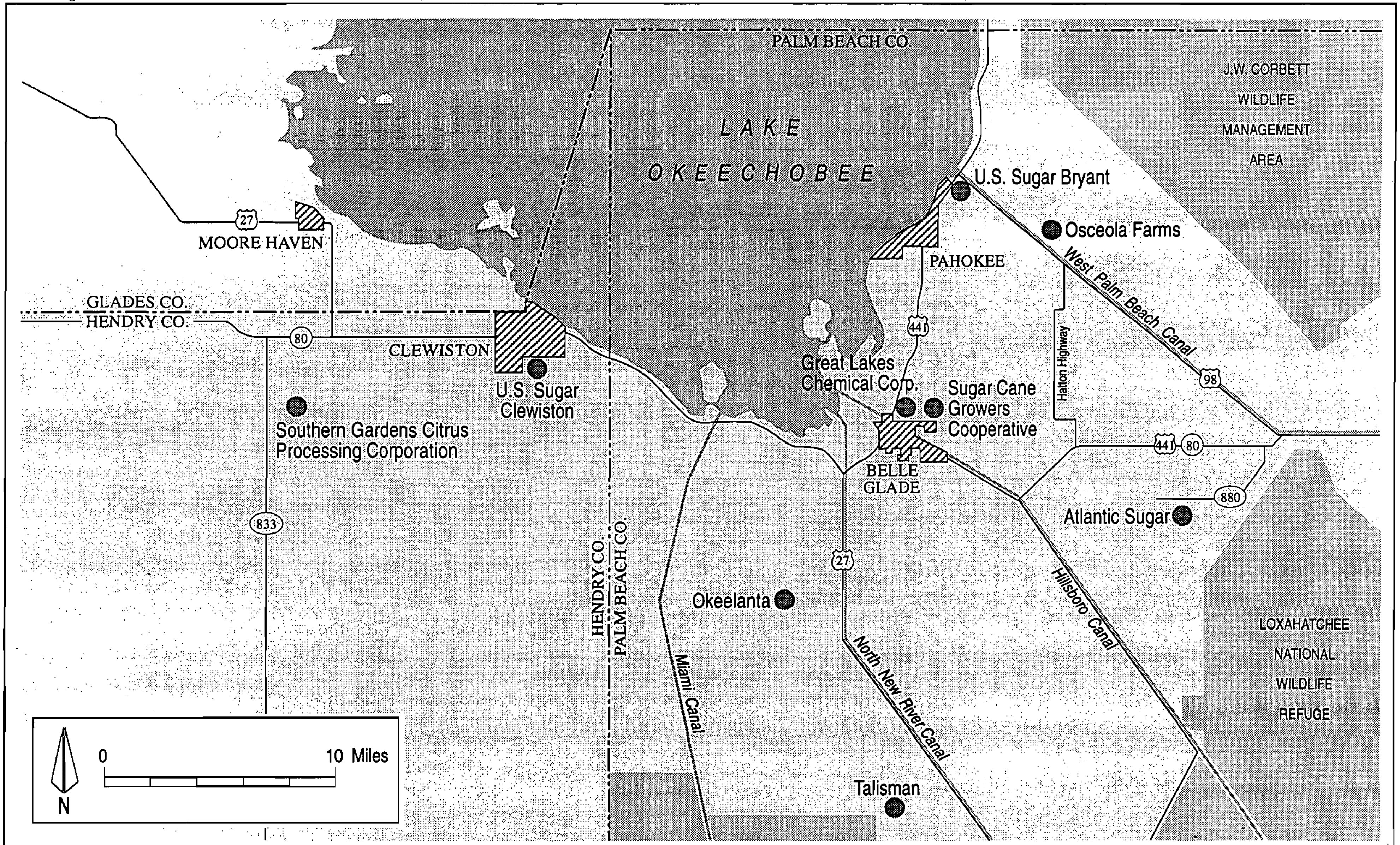

Figure 2-1
Regional Site Map

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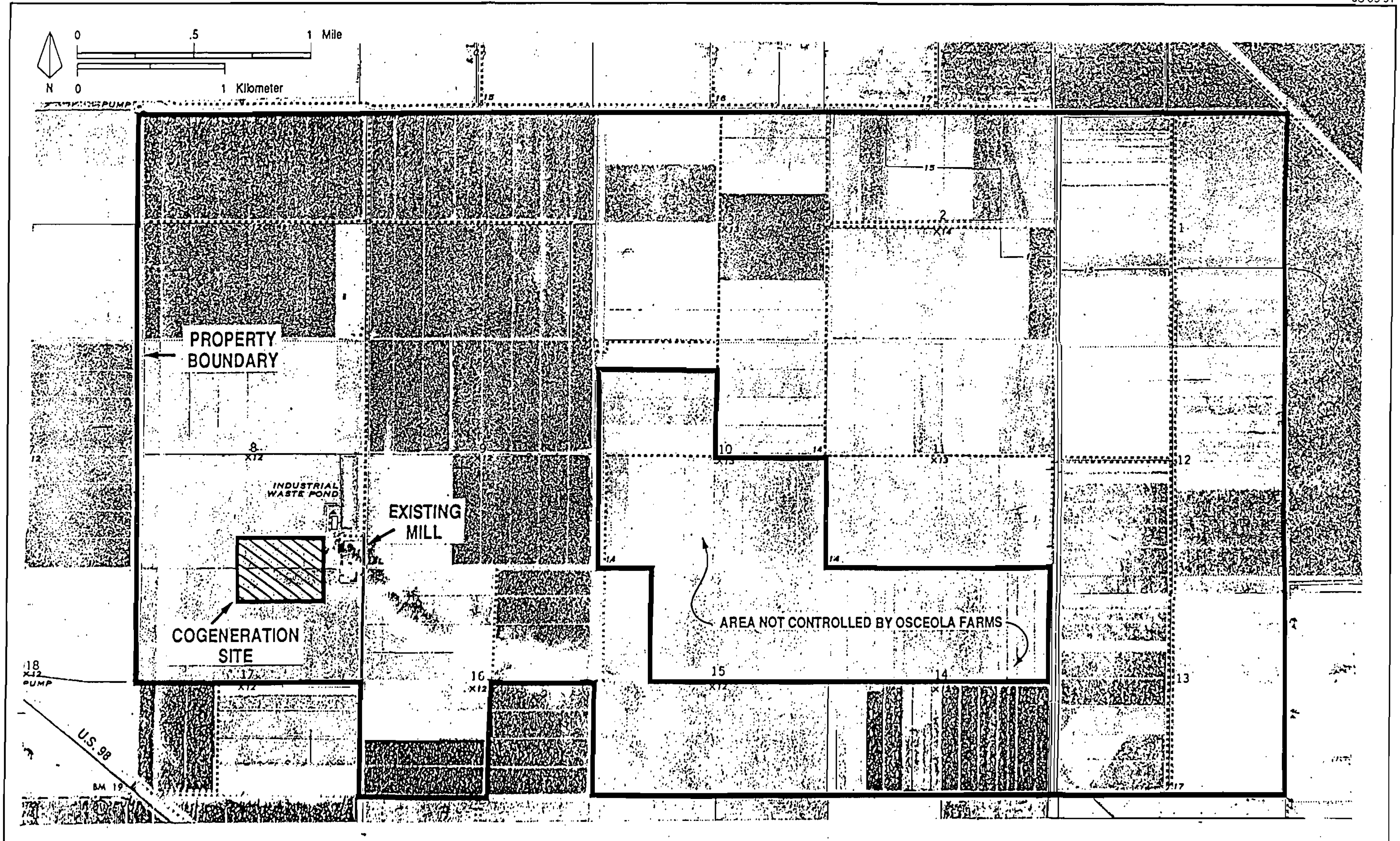

Figure 2-2
Site Location Map

Source: USGS, 1970.

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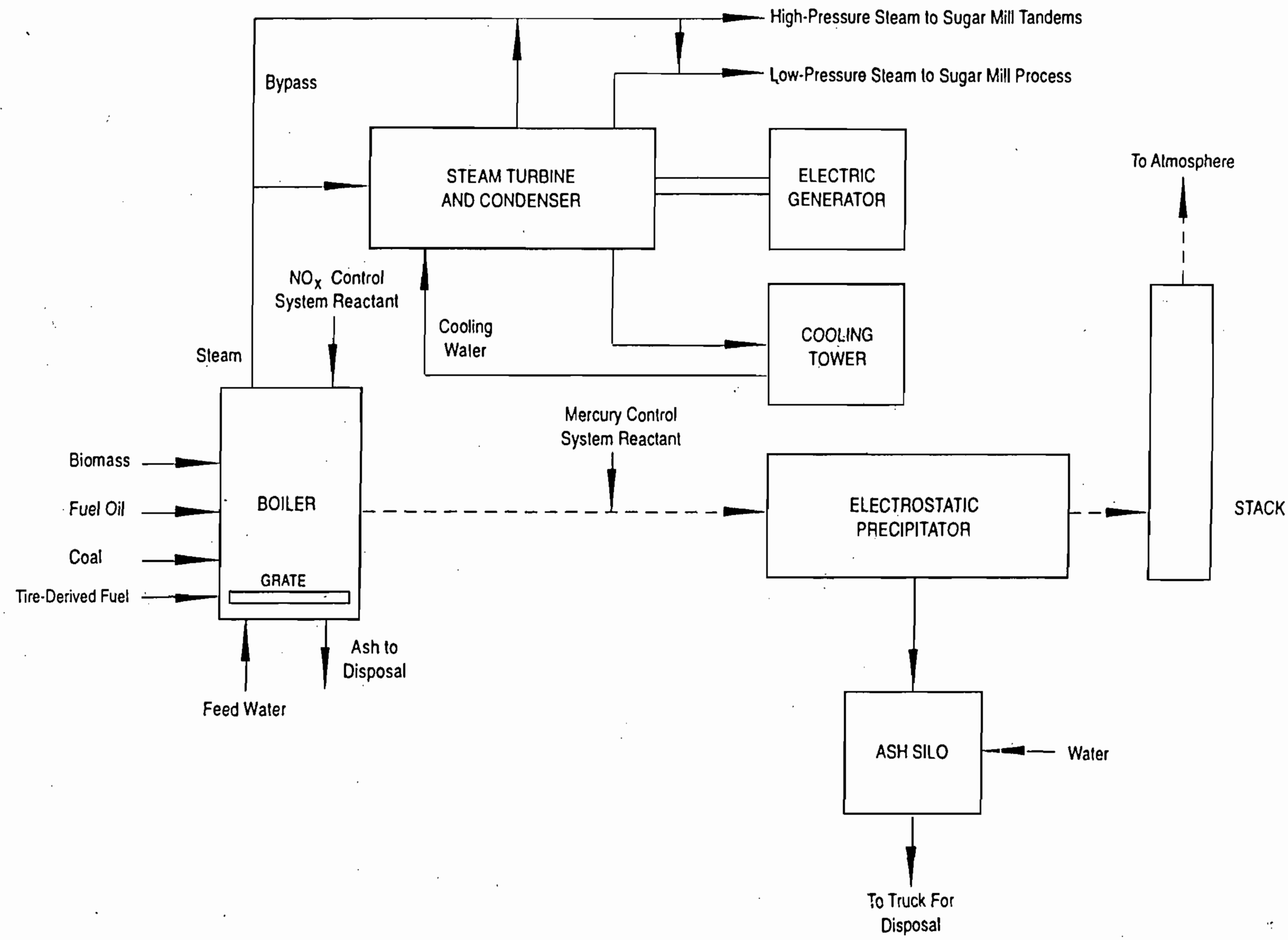

Figure 2-3
Simplified Flow Diagram for Osceola Power Cogeneration Facility

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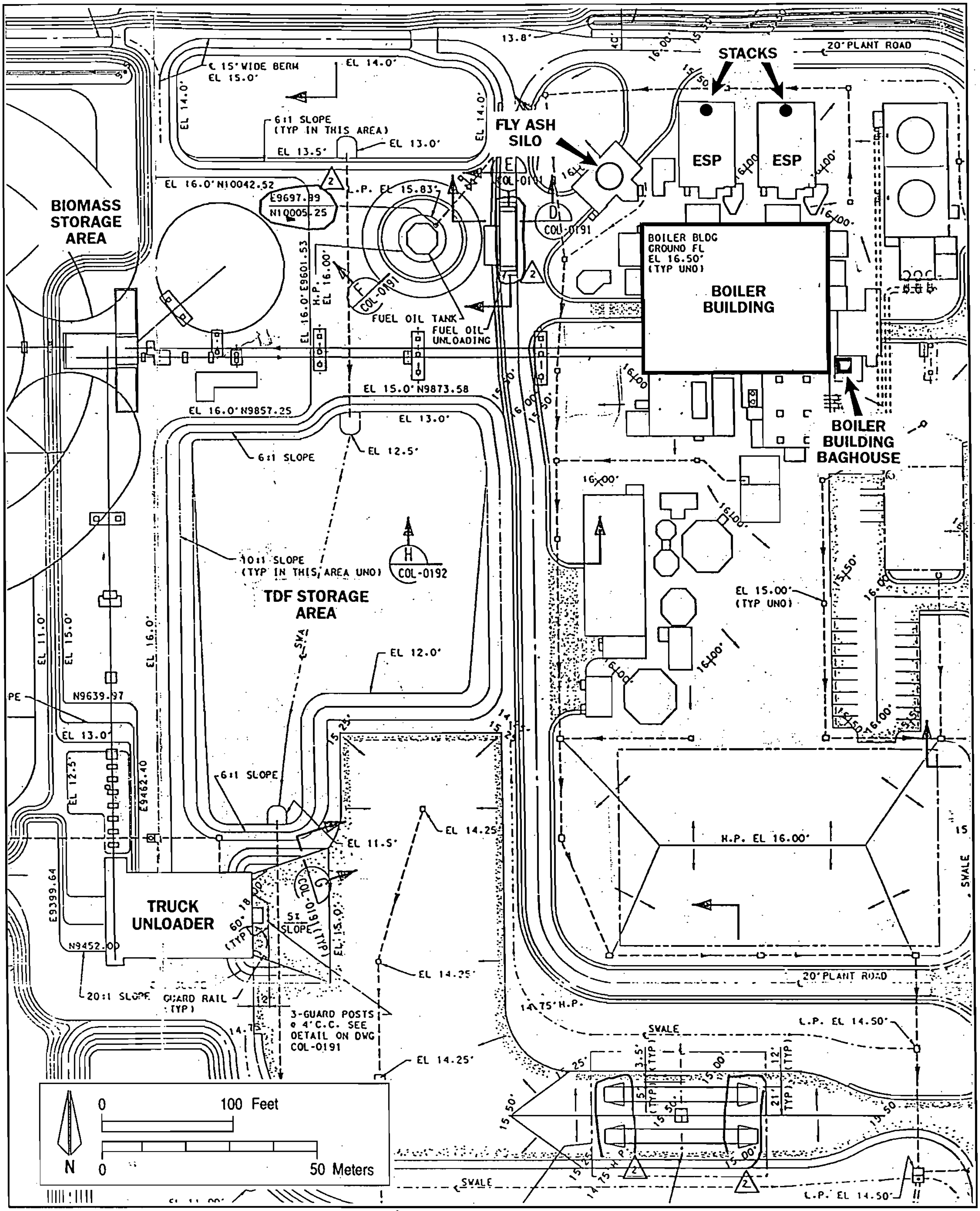

Figure 2-4
Plot Plan of Osceola Power Facility

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3.0 AIR QUALITY REVIEW REQUIREMENTS AND SOURCE APPLICABILITY

The following discussion pertains to federal and state new source review requirements and their applicability to Osceola Power's proposed revisions. These requirements must be satisfied before the revisions can be implemented.

3.1 NATIONAL AND STATE AAQS

The existing applicable national and Florida ambient air quality standards (AAQS) are presented in Table 3-1. National primary AAQS were promulgated to protect the public health, and national secondary AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as non-attainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Federal PSD requirements are contained in the Code of Federal Regulations (CFR), Title 40, Part 52.21, prevention of significant deterioration of air quality. The State of Florida has adopted PSD regulations [Rule 62-212.400, Florida Administrative Code (F.A.C.)] that essentially are identical to the federal regulations. PSD regulations require that all new major stationary facilities or major modifications to existing major facilities which emit air pollutants regulated under CAA be reviewed and a construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by the U.S. Environmental Protection Agency (EPA) and PSD approval authority in Florida has been granted to FDEP.

A "major facility" is defined under Florida PSD regulations as any one of 28 named source categories that has the potential to emit 100 tons per year (TPY) or more of any pollutant regulated under the CAA, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. An "emission unit" is defined as any part or activity of a facility that has the potential to emit any air pollutant. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant, considering the application of control equipment and any other federally enforceable limitations on the emission units' capacity. A "major modification" is defined under PSD regulations as a change at an existing major stationary facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Major new facilities and major modifications are required to undergo the following analyses related to PSD for each pollutant emitted in significant amounts:

1. Source information,
2. Control technology review,
3. Source impact analysis,
4. Preconstruction air quality monitoring analysis, and
5. Additional impact analyses.

In addition to these analyses, a new source also must be reviewed with respect to good engineering practice (GEP) stack height regulations. If the proposed new source or modification is located in a non-attainment area for any pollutant, the source may be subject to non-attainment new source review requirements.

Discussions concerning each of these requirements are presented in the following sections.

3.2.2 INCREMENTS/CLASSIFICATIONS

The 1977 CAA amendments address the prevention of significant deterioration of air quality. The law specifies that certain increases in air quality concentrations above the baseline concentration level of SO_2 and total suspended particulate matter [PM(TSP)] would constitute significant deterioration. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or will have an impact. Congress also directed EPA to evaluate PSD increments for other criteria pollutants and, if appropriate, promulgate PSD increments for such pollutants.

Three classifications were designated, based on criteria established in the CAA amendments. Certain types of areas (international parks, national wilderness areas, memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) were designated as Class I areas. All other areas of the country were designated as Class II. PSD increments for Class III areas were defined, but no areas were designated as Class III. However, Congress made provisions in the law to allow the redesignation of Class II areas to Class III areas. PSD increments for Class III areas are higher than those for Class II increments.

In 1978, EPA promulgated PSD regulations related to the requirements for classifications, increments, and area designations as set forth by Congress. PSD increments were initially set for only SO_2 and PM(TSP). However, in 1988, EPA promulgated final PSD regulations for NO_x and established PSD increments for nitrogen dioxide (NO_2). On June 3, 1993, EPA promulgated PSD increments for particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (PM10). The PM10 increments replaced the PM(TSP) increments.

The current federal PSD increments are shown in Table 3-1. As shown, Class I increments are the most stringent, allowing the smallest amount of air quality deterioration, while the Class III increments allow the greatest amount of deterioration. FDEP has adopted the EPA class designations and allowable PSD increments for PM10, SO_2, and NO_2.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a fictitious concentration level corresponding to a specified baseline date and certain additional baseline sources. In reference to the baseline concentration, the baseline date actually includes three different dates:

1. The major source baseline date, which is January 6, 1975, in the cases of SO_2 and PM10, and February 8, 1988, in the case of NO_2;
2. The minor source baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application; and
3. The trigger date, which is August 7, 1977, for SO_2 and PM10, and February 8, 1988, for NO_2.

By definition in the PSD regulations, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable minor source baseline date, and

2. The allowable emissions of major stationary facilities that began construction before January 6, 1975, for SO_2 and PM10 sources, or February 8, 1988, for NO_x sources, but which were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and, therefore, affect PSD increment consumption:

1. Actual emissions representative of a major stationary facility on which construction began after January 6, 1975, for SO_2 and PM10 sources, and after February 8, 1988, for NO_x sources; and
2. Actual emission increases and decreases at any stationary facility occurring after the major source baseline date that result from a physical change or change in the method of operation of the facility.

The minor source baseline date for SO_2 and PM10 has been set as December 27, 1977, for the entire State of Florida [Rule 62-212.400, F.A.C.). The minor source baseline date for NO_2 has been set as March 28, 1988, for all of Florida.

3.2.3 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that BACT be applied to control emissions from the facility or modification [Rule 62-212.400(5)(c), F.A.C]. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in Rule 62-212.200, F.A.C. as:

> An emissions limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the department, on a case by case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall,

> to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation.

The requirements for BACT were promulgated within the framework of PSD in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's Guidelines for Determining Best Available Control Technology (BACT) (EPA, 1978) and in the PSD Workshop Manual (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980),

> BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis.

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed or modified facility. BACT must, as a minimum, demonstrate compliance with New Source Performance Standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected.

EPA issued a draft guidance document in 1990 on the top-down approach entitled Top-Down Best Available Control Technology Guidance Document (EPA, 1990a). The "draft" guidance requires starting with the most stringent (or top) technology and emissions limits that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified.

It is noted that the American Paper Institute (API) initiated legal action in 1989 against the EPA over the implementation of the top-down approach. EPA and API reached a settlement agreement (July 9, 1991) which requires EPA to initiate formal rulemaking for BACT procedures. A proposed rule was required by January, 1992, but has not yet been published. However, until new rules are issued, EPA and FDEP is requiring that the top-down approach still be used to determine BACT.

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), F.A.C, any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (EPA, 1987a).

Under the exemption rule, FDEP may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 [Rule 62-212.400, F.A.C.].

3.2.5 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major facility or major modification subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rates shown in Table 3-2 [Rule 62-212.400(5)(d) F.A.C.]. The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval.

Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (EPA, 1987b). The source impact analysis for criteria pollutants can be limited to the new or modified facility if the net increase in impacts as a result of the new or modified source is below modeling significance levels, as presented in Table 3-1.

Various lengths of record for meteorological data can be used for impact analyses. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If less than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor must normally be used for comparison to air quality standards.

3.2.6 ADDITIONAL IMPACT ANALYSES

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analysis of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed or modified facility [40 CFR 52.21; Rule 62-212.400(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts from general commercial, residential, industrial, and other growth associated with the facility or modification also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.2.7 GOOD ENGINEERING PRACTICE STACK HEIGHT

The 1977 CAA amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985). Identical regulations have been adopted by FDEP [Rule 62-210.550, F.A.C.]. GEP stack height is defined as the highest of:

1. 65 meters (m); or
2. A height established by applying the formula:

   Hg = H + 1.5L

   where: Hg = GEP stack height,
   H = Height of the structure or nearby structure, and
   L = Lesser dimension (height or projected width) of nearby structure(s); or
3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature but not greater than 0.8 kilometer (km). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula. Because the terrain in the vicinity of the Osceola Power facility is generally flat, plume impaction was not considered in determining the GEP stack height.

3.3 NON-ATTAINMENT RULES

Based on the current non-attainment provisions (Rule 62-212.500, F.A.C.), all major new facilities and modifications to existing major facilities located in a non-attainment area must undergo non-attainment review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the non-attainment pollutant, or if the modification results in a significant net emission increase of the non-attainment pollutant.

For major facilities or major modifications that locate in an attainment or unclassifiable area, the non-attainment review procedures apply if the source or modification is located within the area of influence of a non-attainment area. The area of influence is defined as an area that is outside the boundary of a non-attainment area but within the locus of all points that are 50 km outside the boundary of the non-attainment area. Based on Rule 62-212.500(2)(a), F.A.C., all VOC facilities or emission units that are located within an area of influence are exempt from the provisions of new source review for non-attainment areas. Facilities or emissions units that emit other non-attainment pollutants and are located within the area of influence are subject to non-attainment review unless the maximum allowable emissions do not have a significant impact within the non-attainment area.

The nonattainment regulations also require that major sources of VOC and NO_x apply reasonably available control technology (RACT) to control emissions (Rule 62-296.570). The RACT rule specifies specific emission limits for certain source types. The specific source category that is applicable to Osceola Power is contained in Rule 296.570(4)(b)6, which limits emissions from carbonaceous fuel burning facilities to 5.0 lb/MMBtu for VOC and 0.9 lb/MMBtu for NO_x.

3.4 SOURCE APPLICABILITY

3.4.1 PSD REVIEW

3.4.1.1 Pollutant Applicability

Osceola Power is located in Palm Beach County, which has been designated by EPA and FDEP as a maintenance area for ozone. Palm Beach County and surrounding counties are designated as PSD Class II areas for SO_2, PM10, and NO_2.

The Osceola Power facility is considered to be an existing major stationary facility because potential emissions of certain regulated pollutants exceed 100 TPY. As a result, Osceola Power received a state and federal PSD construction permit in 1993, and a revised PSD permit in 1995. PSD review was triggered for SO_2, beryllium, and fluorides. The facility is now operating and has conducted initial compliance testing on wood waste. Compliance testing on bagasse has not yet been conducted. Osceola Power is now proposing changes to the emissions limits of four pollutants for biomass firing and desires to amend the PSD construction permit. The averaging time specified for the CO emissions limit for all fuels is also being revised.

A revised PSD source applicability analysis for Osceola Power, incorporating these changes, is provided in Table 3-3. The emissions also reflect the request to burn TDF. Since the facility does not yet have a two-year operational history, the baseline emission rates presented in the PSD application in 1995 were used. As shown, based on the permit limits and the Osceola Power maximum annual emissions, PSD review will be triggered only for NO_x. PSD is triggered for NO_x since the proposed emission limit will increase potential emissions by greater than 40 TPY.

Although PSD review for CO, SO_2, Pb, or Hg is not being triggered by the proposed modification, changes are occurring in emission rates for some hazardous/toxic air pollutants. As a result, the previous modeling analysis for these pollutants has been updated. Since the proposed modification triggers PSD review for NO_x, a modeling analysis was performed for NO_x. The analysis is provided in Section 5.0.

3.4.1.2 <u>Ambient Monitoring</u>

Based upon the increase in emissions from Osceola Power's proposed project, a PSD preconstruction ambient monitoring analysis is required for NO_x. However, if the increase in impacts of a pollutant is less than the *de minimis* monitoring concentration, then an exemption from the preconstruction ambient monitoring requirement may be granted for that pollutant. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

A comparison of the net increase in NO_x impacts due to the proposed project and the *de minimis* monitoring concentrations is presented in Table 3-4. The air quality impact analysis presented in Section 5.0 demonstrates that the maximum NO_x impacts resulting from the net increase in emissions will be below the *de minimis* monitoring concentration. Therefore, the project may be exempted from the preconstruction monitoring analysis.

3.4.1.3 Best Available Control Technology

The federal PSD regulations [40 CFR 52.21(j)(3)] state that BACT is required for each pollutant for which the modification results in a net emissions increase. BACT must be applied to each emissions unit in which a net emissions increase in a PSD pollutant would occur as a result of a physical change or a change in the method of operation in the unit. As discussed in Section 2.0, only the emission limits for boiler units at Osceola Power are being changed. As a result, BACT for NO_x only applies to the two boilers.

3.4.2 NONATTAINMENT REVIEW

The Osceola Power is located in Palm Beach County, which has been designated as an attainment or maintenance area for all pollutants except ozone. There will be no increase in VOC emissions due to the proposed request. As a result, nonattainment review does not apply to the proposed project.

The Osceola Power facility received a RACT determination for NO_x when originally permitted in 1993. The current RACT rule applicable to Osceola Power [Rule 62-296.570(4)(b)6] is the RACT for carbonaceous fuel-fired boilers. The RACT rule limits NO_x emissions to 0.90 lb/MMBtu and VOC emissions to 5.0 lb/MMBtu. The proposed NO_x emission limit of 0.15 lb/MMBtu, and current VOC limits for bagasse (0.06 lb/MMBtu) and woodwaste (0.04 lb/MMBtu), for carbonaceous fuel firing comply with the RACT rule.

3.4.3 NEW SOURCE PERFORMANCE STANDARDS

Federal New Source Performance Standards (NSPS) have been promulgated for electric utility boilers in the electric utility industry (40 CFR 60, Subpart Da). These standards currently apply to the Osceola Power boilers, and will continue to apply in the future. The boilers are also subject to a record keeping requirement under the NSPS for municipal waste combustors (MWCs) (40 CFR 60, Subparts Ea and Cb) since Osceola Power potentially burns wood waste materials which would be defined as municipal solid waste due to the origin of the fuel.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significance Levels

Pollutant	Averaging Time	AAQS (μg/m³) National Primary Standard	AAQS (μg/m³) National Secondary Standard	AAQS (μg/m³) State of Florida	PSD Increments (μg/m³) Class I	PSD Increments (μg/m³) Class II	Significant Impact Levels (μg/m³)
Particulate Matter (PM10)	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150[b]	150[b]	150[a]	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365[b]	NA	260[a]	5	91	5
	3-Hour Maximum	NA	1,300[b]	1,300[a]	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000[b]	10,000[b]	10,000[a]	NA	NA	500
	1-Hour Maximum	40,000[b]	40,000[b]	40,000[a]	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone	1-Hour Maximum[c]	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	15	NA	NA	NA

Note: AAQS = Ambient Air Quality Standards.
NA = Not applicable, i.e., no standard exists.
Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
PSD = prevention of significant deterioration.
μg/m³ = micrograms per cubic meter.

[a]Maximum concentration not to be exceeded more than once per year.
[b]Achieved when the expected number of exceedances per year is less than 1.
[c]Achieved when the expected number of days per year with concentrations above the standard is less than 1.

Sources: 40 CFR 50.
40 CFR 52.21.
Rule 62-272, F.A.C.

Table 3-2. PSD Significant Emission Rates and *De Minimis* Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter (TSP)	NAAQS, NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Oxides	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (ozone)	NAAQS, NSPS	40	100 TPY[a]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Asbestos	NESHAP	0.007	NM
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour
MWC	NSPS	3.5×10^{-6}	NE
MWC Metals (as PM)	NSPS	15	NE
MWC Acid Gases (SO_2 + HCl)	NSPS	40	NE
MSW Landfill Gases (as NMOC)	NSPS	50	NE

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below *de minimis* monitoring concentrations.

HCl = hydrogen chloride.
MSW = municipal solid waste.
MWC = municipal waste combustor.
NAAQS = National Ambient Air Quality Standards.
NE = not yet established.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
NM = no ambient measurement method.
NMOC = non-methane organic carbon.
NSPS = New Source Performance Standards.
PM = particulate matter.
PM10 = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
PSD = prevention of significant deterioration.
SO_2 = sulfur dioxide.
TPY = tons per year.
TSP = total suspended particulate matter.
$\mu g/m^3$ = micrograms per cubic meter.

[a] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

Source: 40 CFR 52.21; Golder Associates Inc. 1997.

Table 3-3. PSD Source Applicability Analysis for Osceola Power Limited Partnership Facility

Regulated Pollutant	Original PSD Baseline Emissions (TPY)	Cogeneration Facility Annual Emissions (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	Current Permit Limit (TPY)	PSD Applies?	Permit Amendment Required?
Particulate (TSP)	357.7	144.2[a]	-213.5	25	123.1[d]	No	No
Particulate (PM10)	321.9	139.0[b]	-182.9	15	123.1[d]	No	No
Sulfur dioxide	178.5	339.0	160.5	40	339.0	No	No
Nitrogen oxides	437.8	626.9	189.1	40	477.1	Yes	Yes
Carbon monoxide	5,992.3	1,436.4	-4,555.9	100	1,436.4	No	No
Volatile org. compds.	208.6	219.2	10.6	40	219.2	No[c]	No
Lead	0.16	0.27	0.11	0.6	0.011	No	Yes
Mercury	0.0158[d]	0.0168	0.0010	0.1	0.0168	No	Yes
Beryllium	0.00002	0.0013	0.00128	0.0004	0.0013	No	No
Fluorides	0.0079	5.25	5.24	3	5.25	No	No
Sulfuric acid mist	5.36	6.00	0.64	7	6.00	No	No
Total reduced sulfur	—	—	0	10	—	No	No
Asbestos	—	—	0	0.007	—	No	No
Vinyl Chloride	—	—	0	0	—	No	No

[a] Includes 123.1 TPY from boilers and 21.1 TPY from fugitive dust emission sources.
[b] Includes 123.1 TPY from boilers and 15.9 TPY from fugitive dust emission sources.
[c] Nonattainment review does not apply since the increase in VOC emissions is less than 40 TPY.
[d] Does not include fugitive dust emissions.

Table 3-4. Comparison of Net Increase in Impacts to the *De Minimis* Monitoring Concentrations

Pollutant	Net Increase in Impacts Due to Proposed Project ($\mu g/m^3$)	*De Minimis* Monitoring Concentration ($\mu g/m^3$)	Preconstruction Ambient Monitoring Analysis Required?
Nitrogen Oxides	0.10	14, annual	No

Source: Golder Associates Inc., 1997.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY FOR NITROGEN OXIDES

4.1 REQUIREMENTS

The 1977 Clean Air Act Amendments established requirements for the approval of preconstruction permit applications under the PSD program. One of these requirements is that the best available control technology (BACT) be installed for applicable pollutants. BACT determinations must be made on a case-by-case basis considering technical, economic, energy, and environmental impacts for various BACT alternatives. To bring consistency to the BACT process, the EPA developed the so called "top-down" approach to BACT determinations. As mentioned previously, this approach has been challenged in court and a settlement agreement reached which requires EPA to initiate formal rulemaking on the top down approach. Nonetheless, in the absence of formal rules related to this approach, the "top-down" approach is followed in the BACT analysis for Osceola.

The first step in a top-down BACT analysis is to determine, for each applicable pollutant, the most stringent control alternative available for a similar source or source category. If it can be shown that this level of control is not feasible on the basis of technical, economic, energy, or environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration.

In the case of the proposed revisions for Osceola, only NO_x emissions form the boilers requires BACT analysis. The following sections present the BACT analysis.

4.2 POLLUTANT FORMATION

NO_x is formed in the boiler during the combustion process. Nitrogen is present in both the fuel and in the combustion air and combines with oxygen in the combustion air to form primarily nitric oxide (NO). A small fraction of the NO is further oxidized to form nitrogen dioxide (NO_2). NO_x formed from the fuel nitrogen is termed "fuel" NO_x, and that formed from the nitrogen in the combustion air is termed "thermal" NO_x.

Biomass (bagasse and wood waste) fired in the boilers has low nitrogen content, typically less than 0.5 percent (dry basis). As a result, fuel NO_x is low from biomass-fired boilers. Thermal NO_x is the primary emission from such boilers.

In general, biomass-fired boilers have relatively low NO_x emissions compared to fossil fuel-fired boilers. Proper air/fuel mixing and staged combustion reduce the formation of NO_x. Emission rates from different boilers vary because of manufacturer differences, differences in firing configurations, and also because in fuel type and fuel quality. However, the general factors affecting NO_x emissions from such boilers include the following:

1. Air/fuel ratio and mixing between fuel and air;
2. Fuel nitrogen content and other fuel characteristics;
3. Burner or firing type; and
4. Combustion temperatures;

4.3 OSCEOLA'S BIOMASS-FIRED BOILERS

Osceola's boiler manufacturer has estimated that uncontrolled NO_x emissions from the spreader stoker boilers when burning biomass are approximately 0.4 lb/MMBtu. The use of a urea based selective non-catalytic reduction (SNCR) system reduces the NO_x level to 0.12 lb/MMBtu, which is Osceola's allowable emission limit based on a 30-day rolling average. This level of control results in an approximate 70% NO_x reduction and an outlet concentration of about 70 ppmvd. The SNCR system, coupled with the NO_x continuous emission monitors, continuously regulates the amount of urea injected into the boilers in order to meet the emission limit.

Osceola has over the last nine months experienced significant boiler downtime due to superheater tube replacement. Superheater tube failure has occurred frequently, requiring boiler shutdown and repair. From December 1996 through March 1997, outages due to superheater tube failure occurred on 40 days for Boiler A and for 25 days on Boiler B, resulting in potential lost electric generation of 38,000 MW-hrs and repair costs of $600,000. These data are summarized in Table 4-1.

The identical three boilers at Okeelanta have not experienced nearly the degree of superheater tube failure as the Osceola boilers. The Okeelanta boilers are identical in size to the Osceola boilers, burn the same fuels, and are operated in the same manner. The only significant difference in the operations is the lower NO_x emission limit for the Osceola boilers, requiring higher urea injection rates. During the period February through June 1997, the urea injection rates for the Osceola boilers averaged 1.1 gal/MW-hr, or about 35 gal/hr per boiler. Peak urea usage rates have been as high as 70 gal/hr per boiler. Based on operational experience at Okeelanta, the Okeelanta boilers use much less urea.

Although many factors can contribute to superheater tube failure, the only significant difference in operation between the Osceola and Okeelanta facilities is the amount of urea injection required due to the different NO_x limits. As a result, it is concluded that the superheater tube failures are accelerated by the higher urea injection rates.

The increased urea usage is about 40 percent higher for Osceola's boilers to meet the current NO_x emission limit of 0.12 lb/MMBtu, compared to Okeelanta's boilers, which have an emission limit of 0.15 lb/MMBtu. Based on the boiler manufacturer's estimated uncontrolled emission rate of 0.4 lb/MMBtu, the NO_x removed efficiency is 70 percent for Osceola, while for Okeelanta the removal efficiency is 62.5 percent (see Table 4-2). Thus, an additional 7.5 percent reduction in NO_x emissions requires 40 percent more urea usage.

In addition, the urea injection required for Osceola's boilers to meet a 0.12 lb/MMBtu limit produces a molar usage substantially higher than Okeelanta, and in the upper range of all SNCR projects based upon an EPRI survey. As shown in Table 4-2, for Osceola the urea molar ratio is 2.78, while for Okeelanta the ratio is about 2.2. The lower urea usage at Okeelanta is within the typical range (although at the upper end of the envelope) of urea usage for SNCR at utility scale applications.

The excessive urea usage at Osceola has not only contributed to the boiler damage but to increased emissions of urea's decomposition products which include ammonia slip and carbon dioxide. These are being emitted at much greater rates with the NO_x emission level of 0.12 lb/MMBtu. Osceola has recently conducted testing of ammonia slip emissions and found the ammonia slip to be in the range of 50 to 100 ppm. This level of ammonia slip is high and can lead to ammonium bisulfate formation, which can cause fouling of the air preheater and the ESP.

High ammonia slip can also combine with hydrogen chloride in the flue gas to from ammonium chloride. The ammonium chloride can form a detached plume of high opacity.

In addition, the high urea usage rate at Osceola has been linked to decreased effectiveness of the ESP and high opacity readings. In December, 1996, ABB performed an inspection of the ESPs at Osceola and concluded that poor ESP performance is related to a decrease in resistivity of the particulate in the flue gas stream, and results from the high ammonia levels in the flue gas and the high moisture in the fuel.

4.4 ECONOMIC IMPACT

The cost to Osceola of the higher urea injection rates include the cost of urea, repair of the superheater tubes, and lost revenue due to lost electric generation. A economic analysis of the impact of the higher urea rates is presented in Table 4-3. Actual costs incurred over the period December 1996 through March 1997 were obtained, and prorated to an annual basis. The cost of lost electric generation was conservatively calculated based on the base electric rate of $16.40/Mw-hr from Florida Power & Light Company (FP&L). Although currently in litigation, capacity payments under the power sales contract with FP&L would also be adversely affected, resulting in even greater economic impact to Osceola.

As shown in Table 4-3, the total annual cost of higher urea injection is estimated to be $3.8 million per year. The reduction in NO_x emissions due to the higher injection is calculated based upon the difference between limits of 0.12 lb/MMBtu and 0.15 lb/MMBtu. This results in an emission reduction of 150 TPY of NO_x. Thus, the incremental cost effectiveness of the higher urea injection is over $25,000/ton of NO_x removed.

4.5 ALTERNATIVE NO_X CONTROL TECHNOLOGIES

Based on information contained in the BACT/RACT/LAER Clearinghouse EPA database, all BACT determinations issued within the past 5 years for NO_x emissions from wood-fired boilers are summarized in Table 4-4. Review of this table shows that most determinations are based on SNCR technology. A few determinations have been based on combustion control and boiler design and operation. Of the BACT determinations requiring SNCR, only a few have NO_x limits of less than 0.15 lb/MMBtu. A discussion of each of these is provided below:

Multitrade LP - 0.1 lb/MMBtu; is a peaking boiler, not base load unit, and therefore is not directly comparable to Osceola.

SAI Energy - 0.023 lb/MMBtu; is a fluidized bed unit, therefore not directly comparable to Osceola; also, was never constructed.

Scott Paper - 43 ppm - Limit could not be met by Scott Paper; plan on raising to 86 ppm (similar to 0.15 lb/MMBtu).

Based on this review, it is concluded that Osceola's proposed limit of 0.15 lb/MMBtu is consistent with previous BACT determinations for wood fired boilers.

In addition to SNCR, NO_x emissions potentially can be controlled by a post-combustion NO_x reduction system known as selective catalytic reduction (SCR). Performance of an SCR system downstream of a wood-fired boiler is difficult to predict. Such a system is not known to have been applied to a wood-fired boiler. This NO_x reduction system uses a vanadium pentoxide catalyst to promote the reaction of ammonia with the NO_x. The presence of sodium compounds in the gas stream, however, is likely to cause catalyst fouling and plugging problems. In addition, the formation of ammonia bisulfate as a result of sulfur compounds in the gas stream would lead to corrosion and plugging of downstream components, compounding the uncertainty associated with this NO_x reduction system.

SCR has been applied to coal-fired boilers, and is considered technically feasible for a biomass-fired boiler. However, downstream fouling has been a problem in such facilities. Also, applying this technology to the existing Osceola boilers, which already have an SNCR system, would require extensive and costly retrofitting. Based on these considerations, SCR technology is not considered as an option for Osceola, and was not considered further.

4.6 PROPOSED BACT FOR NO_X

The current SNCR control system is the only economically feasible NO_x control technique applicable to the existing Osceola biomass-fired boilers. Osceola underwent PSD review in 1993 and at the time agreed to an SNCR system in order to not increase NO_x emissions above existing emissions from Osceola Farms sugar mill boilers. The self-imposed limit was 0.12 lb/MMBtu, lower than the Okeelanta limit of 0.15 lb/MMBtu. However, at the time Osceola did not have knowledge of the detrimental effect that higher urea injection rates would have on boiler and EPS operation.

Review of information contained in the BACT/LAER Clearinghouse documents (Table 4-3) indicates that previous NO_x BACT emission limits have generally ranged from 0.15 lb/MMBtu to 0.3 lb/MMBtu. Determinations requiring lower limits were for sources that were never built or for sources which could not meet the BACT limit.

The proposed BACT emission level of 0.15 lb/MMBtu will allow Osceola to operate under the same conditions as at Okeelanta, where significant superheater tube failure has not occurred. The change is expected to reduce the frequency of superheater tube failure at Osceola and improve ESP operation. The air dispersion modeling analysis presented in Section 5.0, and the additional impact analysis described in Section 6.0, demonstrates that the increase in NO_x emissions will have insignificant effect upon air concentrations in the area, and no impact upon soils, vegetation or visibility in the area.

Table 4-1. Outages and Repairs to Superheater Tubes at Osceola Power, December 1996 - March 1997

Outage		Osceola Cogeneration Plant Superheater Failure Log		
From	To	Outage Days	Lost Generation[a] (MWH)	Repair Costs[b] (Avg.)
Unit A				
11/26/96	12/2/96	7	4200	$66,500
12/30/96	1/1/97	3	1800	$28,500
1/22/97	1/24/97	3	1800	$28,500
1/28/97	2/7/97	11	6600	$104,500
3/2/97	3/3/97	2	1200	$19,000
3/10/97	3/13/97	4	2400	$38,000
3/22/97	3/22/97	1	600	$9,500
3/24/97	4/1/97	9	5400	$85,500
Unit B				
11/17/96	11/19/96	3	1800	$28,500
12/20/96	12/20/96	1	600	$9,500
2/6/97	2/7/97	2	1200	$19,000
2/11/97	2/18/97	8	4800	$76,000
3/23/97	3/31/97	9	5400	$85,500
		Total=	37,800	$598,500

[a] 25 MW net per boiler = 25 x 24 x number of days offline
[b] Includes contract labor and replacement boiler tubes, shields, etc. Does not include plant labor to support contractor and expedite work.

Table 4-2. Current and Proposed Urea Usage to Meet NOx Limits

Parameter	Units	Current Operation	Proposed Operation
Heat Input (per boiler)	MMBtu/hr	760	760
Uncontrolled NOx Emissions	lb/MMBtu	0.4	0.4
	lb/hr	304	304
Emission Limit	lb/MMBtu	0.12	0.15
	lb/hr	91.2	114.0
Emissions Reduction	lb/MMBtu	0.28	0.25
	Percent	70.0%	62.5%
	lb/hr	212.8	190.0
Theoretical Urea Usage	lb/hr	138.8	123.9
	gal/hr	12.58	11.23
Actual Urea Usage	gal/hr	35	25
	lb/hr	386.1	275.8
Actual/Theoretical Ratio		2.78	2.23

Notes:
Molecular weight of Urea [CO(NH2)2] = 60
Density of urea (s.g. = 1.323) = 11.03 lb/gal

Table 4-3. Cost Effectiveness of Using Increased Urea Injection in Osceola's Boilers

Cost Item	Cost Factors	Estimated Cost ($)
DIRECT OPERATING COSTS (DOC):		
(1) Maintenance (a)	$600,000 maintenance cost over 4 months, prorated to annual basis	1,800,000
(2) Chemicals and Materials (b) Urea based chemical	10 gal/hr/boiler @ $1.00/gal	175,200
(3) Lost Generation (c)	37,800 Mw-hrs lost over 4 months @ $16.40/Mw-hr, prorated to annual basis	1,859,760
Total DOC:	(1) + (2) + (3)	3,834,960
CONTROLLED NOx EMISSIONS (TPY) @ 0.12 lb/MMBtu		477
CONTROLLED NOx EMISSIONS (TPY) @ 0.15 lb/MMBtu		627
TOTAL NOx REMOVED (TPY):		150
COST EFFECTIVENESS:	$ per ton of NOx Removed	25,566

Notes:
(a) Based on actual contract labor and replacement boiler tubers incurred during 4 month period, projected to annual basis.
(b) Represents increased urea usage compared to Okeelanta plant. Based on actual urea usage for 4 month period.
(c) Based on actual lost generation incurred during 4 month period, projected to annual basis.

Table 4-4. Summary of BACT Determinations for Wood-Fired Boilers

Company	State	Permit #	Permit Issue Date	Throughput (Units)	Emission Limit	Control Equipment
Wood						
Beaver-Livermore Falls	ME	A-555-72-A-N	09/05/91	534 (MMBtu/hr)	0.15 lb/MMBtu	SNCR, Urea Injection
Georgia-Pacific Corporation - Glostee	MS	0080-00013	04/11/95	244 (MMBtu/hr)	0.3 lb/MMBtu	------------
Kes Chateaugay Project	NY	163400 0116	12/19/94	275 (MMBtu/hr)	0.23 lb/MMBtu	------------
Multitrade Limited Partnership	VA	30871	02/21/92	374 (MMBtu/hr)	0.1 lb/MMBtu	SNCR, Urea Injection
Newman Paper Co.	PA	2014, 92015, 92016	04/24/92	129 (MMBtu/hr)	0.3 lb/MMBtu	Low NOx Burners
Pinetree Power - Tamworth Inc.	NH	33-003-00019	11/15/90	404 (MMBtu/hr)	0.265 lb/MMBtu	------------
Pinetree Power Inc.	NH	33-009-00026	03/27/90	289 (MMBtu/hr)	0.3 lb/MMBtu	------------
SAI Energy, Inc.	CA	7483	12/23/94	245 (MMBtu/hr)	0.023 lb/MMBtu	SNCR, Urea Injection - Fluidized bed with natural gas injection into bed. Never built.
Scott Paper Company	WA	93-AQIO64	07/01/93	718 (MMBtu/hr)	43 ppm @ 7% O2	SNCR, Limit could not be met. Plan on raising to 86 ppm.
Weyerhaeuser Company	MS	0300-00032	05/09/95	90 (MMBtu/hr)	0.23 lb/MMBtu	Combustion Controls
Weyerhaeuser Company	AL	408-S003	10/12/94	91 (MMBtu/hr)	0.23 lb/MMBtu	------------
Multiple Fuels						
Applied Energy Serv & Seminole Kraft Corp	FL	PSD-FL-137	03/28/91	3,189 (MMBtu/hr)	0.29 lb/MMBtu	CFB Boiler (Coal and woodbark fired boiler)
Bear Island Paper Company	VA	50840	10/30/92	690 (MMBtu/hr)	0.15 lb/MMBtu	SNCR (Sludge, Coal, Bark)
Hawaiian Commercial & Sugar Company, Lt	HI	HI 89-01	12/19/91	388 (MMBtu/hr)	28 ppmdv	Staged Combustion/SNCR (Bagasse/Coal) - Circulating Fluidized bed - Never Built.
Milwaukee County Power Plant	WI	91-IRS-091	01/01/92	157 (MMBtu/hr)	0.16 lb/MMBtu	Ammonia Injection (Coal)

Source: EPA's RACT/BACT/LAER Clearinghouse, 1997.

5.0 AIR QUALITY IMPACT ANALYSIS

5.1 GENERAL MODELING APPROACH

An air quality analysis for the Osceola cogeneration facility was conducted for NO_x, which is subject to PSD review. An air modeling analysis was performed to demonstrate compliance with Florida AAQS and the allowable PSD Class I and Class II increments for NO_x. In addition, an impact analysis for all emitted Florida Air Toxics (FATs) pollutants was performed for comparison to FDEP's air reference concentrations (ARCs).

The general modeling approach followed EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For this compliance analysis, a significant impact analysis was performed to determine the distance to which the proposed modification will be in excess of the EPA/FDEP significant impact levels. If the project's impacts are above the significant impact levels, a more detailed modeling analysis is performed. As is FDEP policy, the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable significant impact levels. If the screening analysis indicates that maximum predicted concentrations are above 75 percent of the significant impact levels, modeling refinements are performed.

5.2 MODEL SELECTION

The selection of an appropriate air dispersion model was based on the model's ability to simulate impacts in areas surrounding the Osceola site. Within 50 km of the site, the terrain can be described as simple, i.e., flat to gently rolling. As defined in EPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. Therefore, a simple terrain model was selected to predict maximum ground-level concentrations.

The Industrial Source Complex Short-term (ISCST3, Version 96113) dispersion model (EPA, 1996) was used to evaluate the pollutant emissions from the proposed facility and other existing major facilities. This model is provided by EPA through its Technology Transfer Network (TTN) Bulletin Board Service (BBS). The ISCST3 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term and annual averaging periods. For example, a 24-hour average concentration is based on 24 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

Major features of the ISCST3 model are presented in Table 5-1. The ISCST3 model has both rural and urban mode options which affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the source's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area within a 3-km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The regulatory default options include:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural or urban option,
5. Default vertical potential temperature gradients,
6. Calm wind processing, and
7. Reducing calculated SO_2 concentrations in urban areas by using a decay half-life of 4 hours.

For the PSD Class I analysis, the ISCST3 model was used for estimating impacts at the Everglades National Park (ENP) Class I area.

5.3 MODELING METHODOLOGY

5.3.1 GENERAL

A 5-year hourly meteorological data record was used in the air modeling analysis for predicting maximum pollutant concentrations. For the NO_x air modeling assessment, including the significant impact analysis, AAQS, and PSD Class I and Class II analyses, the highest predicted annual average concentration was compared to all applicable significant impact levels, AAQS, and allowable PSD Class I and Class II increments. For the air toxics modeling analysis, the highest predicted annual, 24-hour, and 8-hour concentrations for the 5 years of meteorology for each air toxic compound was compared to the Florida Ambient Reference Concentrations (FARC).

Refinements of the maximum predicted concentrations are typically performed for the receptors of the screening receptor grid at which the highest and/or HSH concentrations occurred over the 5-year period. Generally, if the maximum concentration from other years in the screening analysis are within 10 percent of the overall maximum concentration, those other concentrations are refined as well. Typically, if the highest and HSH concentrations are in different locations, concentrations in both areas are refined.

Modeling refinements are performed for short-term averaging times by using a denser receptor grid, centered on the screening receptor to be refined. The angular spacing between radials is 2 degrees and the radial distance interval between receptors is 100 m. Annual modeling refinements are developed similarly. If the maximum screening concentration is located on the plant property boundary, additional plant boundary receptors are input, spaced at a 2-degree angular interval and centered on the screening receptor. The domain of the refinement grid extends to all adjacent screening receptors.

The air dispersion model is executed with the refined grid for the entire year of meteorology during which the screening concentration occurred. This approach is used to ensure that a valid HSH concentration is obtained. A more detailed description of the emission inventory, meteorological data, and screening receptor grids used in the analysis, is presented in the following sections.

5.3.2 AIR TOXIC ANALYSIS

One source, representing the Osceola facility's two boilers, was modeled in the ISCST3 model with a generic emission rate of 10.0 grams per second (g/sec) (i.e., 79.365 lb/hr). The selected averaging times were for the 8-hour, 24-hour and annual averaging times. The highest predicted 8- and 24-hour and highest annual concentration in 5 years were selected for comparison to the FARCs.

Short-term (i.e. maximum pound per hour) and annual averaged (i.e., tons per year) emission rates were determined for the Osceola facility for each HAP and air toxic pollutant emitted. The calculations for these emitted compounds are provided in Section 2.0. The short-term emission rates for each pollutant were used for determining compliance with the 8- and 24-hour FARCs, while the annual averaged emissions were used for determining compliance with the annual FARC. Maximum pollutant-specific impacts for each averaging time were determined by multiplying the maximum predicted generic concentrations by the pollutant-specific emission rate and dividing the product by the generic emission rate.

5.4 METEOROLOGICAL DATA

Meteorological data used in the ISCST3 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at West Palm Beach. The 5-year period of meteorological data was from 1987 through 1991. The NWS station at West Palm Beach, located approximately 60 km east of the Osceola site, was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the plant site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

The wind speed, cloud cover, and cloud ceiling values were used in the ISCST meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated with the radiosonde data using the Holzworth approach (1972). Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by EPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions were classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed by using the EPA RAMMET meteorological preprocessor program.

5.5 EMISSION INVENTORY

Stack and operating parameters and NO_x emission rate increases for the Osceola are presented in Table 5-2. Emission rates for air toxics are presented on Tables 2-16 and 2-17.

5.6 RECEPTOR LOCATIONS

5.6.1 SIGNIFICANT IMPACT ANALYSIS

5.6.1.1 Site Vicinity

For the screening analysis, concentrations were predicted at 139 receptors located in a radial grid centered at the midpoint between the Osceola stacks. The receptor grid included 36 receptors for each 10 degree sector located on the following rings: at the plant property; 2, 4, and 6 km in directions beyond plant property.

To the east of the proposed cogeneration facility, the Osceola site surrounds a parcel of land that is not owned or leased by either Osceola or Osceola Farms. For the analysis, this land was considered as accessible to the public (i.e., as ambient air).

The nearest property boundary receptors used for the screening modeling are presented in Table 5-3. All receptor locations are relative to the Osceola facility co-located stack location.

The air modeling analysis used a 5-year hourly meteorological data record for predicting maximum pollutant concentrations. For the NO_x air modeling assessment, including the significant impact analysis, AAQS, and PSD Class I and Class II analyses, the highest predicted annual average concentration will be compared to all applicable significant impact levels, AAQS, and allowable PSD Class I and Class II increments. For the air toxics modeling analysis the highest predicted annual, 24-hour, and 8-hour concentrations in 5 years for each air toxic compound will be compared to the Florida Ambient Reference Concentrations (FARC).

5.6.1.2 Everglades National Park

The Everglades National Park is a PSD Class I area that is located beyond 100 km from the Osceola plant site. In the screening analysis, Everglades National Park is represented by 51 discrete receptors, including 47 receptors covering the eastern and northern boundaries of the park from the Florida Keys to the Gulf of Mexico and 4 receptors inside the northeast corner of Everglades National Park. The Universal Transverse Mercator (UTM) coordinates of these Class I receptors are listed in Table 5-4. Refined modeling was performed for the Class I area by using a receptor spacing of 1.0 km centered on the receptor of interest extending to the adjacent receptors.

5.7 BUILDING DOWNWASH CONSIDERATIONS

The procedures used for addressing the effects of building downwash are those recommended in the ISC3 Dispersion Model User's Guide. The building height, length, and width are input to the model, which uses these parameters to modify the dispersion parameters. For short stacks (i.e., physical stack height is less than H_b + 0.5 L_b, where H_b is the building height and L_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used. The features of the Schulman and Scire method are as follows:

1. Reduced plume rise as a result of initial plume dilution,
2. Enhanced plume spread as a linear function of the effective plume height, and
3. Specification of building dimensions as a function of wind direction.

For cases where the physical stack is greater than H_b + 0.5 L_b but less than GEP, the Huber and Snyder (1976) method is used. For this method, the ISCST model calculates the area of the building using the length and width, assumes the area is representative of a circle, and then calculates a building width by determining the diameter of the circle. For both methods the direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector.

The existing Osceola stacks have heights that are below that required to completely avoid building downwash effects. Therefore, the modeling analysis addresses the effects of aerodynamic downwash for these stacks. To determine the potential for downwash to occur, the following buildings were analyzed from a layout plan of the site.

Building	Height (m)	Length (m)	Width (m)
Existing Osceola Farms Boiler Building	21.34	92.0	70.0
Osceola Boilers 1 & 2	36.88	42.0	23.0

The potential for downwash was determined using the EPA Building Profile Input Program (BPIP, Version 95086).

5.8 AIR QUALITY MODELING RESULTS

5.8.1 SIGNIFICANT IMPACT ANALYSIS

5.8.1.1 Site Vicinity

The maximum air quality impacts from the Osceola NO_x emissions increase only are presented in Table 5-5. As shown, the maximum predicted annual NO_2 concentration is 0.10 $\mu g/m^3$, which is well below the NO_2 significant impact level of 1 $\mu g/m^3$. Therefore, a full impact assessment was not performed for this pollutant to demonstrate compliance with allowable PSD Class II increments and AAQS.

5.8.1.2 Everglades National Park

The air quality NO_2 impact of the proposed Osceola modification on the ENP PSD Class I area is summarized in Table 5-6. The maximum predicted concentration of 0.0013 $\mu g/m^3$ is well below the National Park Service recommended Class I significant impact level of 0.025 $\mu g/m^3$. Based on this predicted impact, a full PSD Class I analysis is not required.

5.8.2 AIR TOXIC ANALYSIS

The maximum predicted annual, 24-hour, and 8-hour generic impacts from the screening analysis are presented in Table 5-7. Based on the screening analysis results, modeling refinements were performed. The results of the refined generic modeling analysis is summarized in Table 5-8. The maximum refined annual, 24-, and 8-hour refined concentrations were used to determine the maximum air toxic and HAP concentrations due to the Osceola facility.

The maximum predicted concentrations for the 8-hour, 24-hour, and annual averaging periods for each HAP and air toxic pollutant is presented in Table 5-9. Table 5-9 indicates the maximum short and annual emission rates, and the maximum impacts for each compound emitted. As shown, all compounds emitted have maximum impacts that are below the FARC for the 8-, 24-hour, and annual averaging times, respectively.

Table 5-1. Major Features of the ISCST3 Model

ISCST3 Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975; Bowers, et al., 1979).
• Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulman and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple emission sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, area, and open pit sources
• Capability to calculate dry and wet deposition, including both gaseous and particulate precipitation scavenging for wet deposition
• Variation of wind speed with height (wind speed-profile exponent law)
• Concentration estimates for 1-hour to annual average times
• Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm for ISCST3; a built-in algorithm for predicting concentrations in complex terrain
• Consideration of time-dependent exponential decay of pollutants
• The method of Pasquill (1976) to account for buoyancy-induced dispersion
• A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
• Procedure for calm-wind processing including setting wind speeds less than 1 m/s to 1 m/s.

Note: ISCST3 = Industrial Source Complex Short-Term.

Source: EPA, 1995.

Table 5-2. Summary of Osceola Power Emission, Stack, and Operating Data Used in the Modeling Analysis

	Coordinates		Stack Data (m)		Operating Data		Modeled NO_x Emissions Increase	
Source Description	X (m)	Y (m)	Height	Diameter	Temperature (K)	Velocity (m/s)	(TPY)	(g/s)
Osceola Power 1 & 2	0	0	68.6	3.05	419.3	15.91	149.8	4.31

Note: g/s = grams per second.

K = Kelvin.

m = meters.

m/s = meters per second.

NO_x = nitrogen oxides.

Table 5-3. Property Boundary Receptors Used in the Modeling Analysis

Direction (degrees)	Distance (m)	Direction (degrees)	Distance (m)
10	3033	190	1040
20	3179	200	1090
30	3449	210	1183
40	3899	220	1337
50	4647	230	1592
60	2252	240	1408
70	2076	250	1297
80	1981	260	1238
90	1951	270	1219
100	2352	280	1238
110	2465	290	1297
120	2048	300	1408
130	1631	310	1592
140	1944	320	1897
150	2041	330	2438
160	1881	340	3179
170	1040	350	3033
180	1024	360	2987

Note: Distances are relative to the Osceola Power boilers stack location.

Table 5-4. Everglades National Park Receptors Used for the Class I Screening Analyses

Receptor	UTM Coordinates (km) East	UTM Coordinates (km) North	Receptor	UTM Coordinates (km) East	UTM Coordinates (km) North
1	557.0	2789.0	27	540.0	2848.6
2	556.6	2792.0	28	535.0	2848.6
3	556.0	2796.0	29	530.0	2848.6
4	553.0	2796.5	30	525.0	2848.6
5	548.0	2796.5	31	520.0	2848.6
6	542.7	2796.5	32	515.0	2848.6
7	542.7	2800.0	33	515.0	2843.0
8	542.7	2805.0	34	515.0	2838.0
9	542.7	2810.0	35	515.0	2832.5
10	542.0	2811.0	36	510.0	2832.5
11	541.3	2814.0	37	505.0	2832.5
12	542.7	2816.0	38	500.0	2832.5
13	544.1	2820.0	39	495.0	2832.5
14	543.5	2824.6	40	494.5	2837.0
15	545.0	2829.0	41	491.5	2841.0
16	545.7	2832.2	42	488.5	2845.5
17	546.2	2835.7	43	483.0	2848.5
18	548.6	2837.5	44	480.0	2852.5
19	550.3	2839.0	45	475.0	2854.0
20	445.0	2839.0	46	473.5	2857.0
21	440.0	2839.0	47	473.5	2860.0
22	550.5	2844.0	48	469.0	2860.0
23	545.0	2844.0	49	464.0	2860.0
24	540.0	2844.0	50	459.5	2864.0
25	550.3	2848.6	51	454.0	2864.0
26	545.0	2848.6			

Note: km = kilometers.
UTM = Universal Transverse Mercator.

Table 5-5. Maximum Predicted NO_x Concentrations for the Proposed Emissions Increase in the Vicinity of the Osceola Power Site

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)	EPA Significant Impact Level ($\mu g/m^3$)
Annual	0.08	300.	4000.	87123187	1.0
	0.08	270.	4000.	88123188	
	0.09	300.	4000.	89123189	
	0.10	270.	4000.	90123190	
	0.09	300.	2000.	91123191	

Note: YY = year, MM = month, DD = day, HH = hour.

[a] All receptor coordinates are reported with respect to the midpoint of the Osceola Power facility stack.

Table 5-6. Maximum Predicted NO_2 Concentrations for the PSD Class I Significant Impact Analysis

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] UTM-E (m)	Receptor Location[a] UTM-N (m)	Period Ending (YYMMDDHH)	NPS Recommended Significant Impact Level ($\mu g/m^3$)
Annual	0.0010	545000.	2848600.	87123187	0.025
	0.0011	540000.	2848600.	88123188	
	0.0013	550300.	2848600.	89123189	
	0.0012	550300.	2848600.	90123190	
	0.0013	550300.	2848600.	91123191	

Note: YY = year, MM = month, DD = day, HH = hour.

[a] All receptor coordinates are reported in Universal Transverse Mercator (UTM) coordinates.

Table 5-7. Maximum Predicted Generic (10 g/s) Concentrations for the Osceola Power Facility: Screening Analysis

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	0.19	300.	4000.	87123187
	0.19	270.	4000.	88123188
	0.20	300.	4000.	89123189
	0.23	270.	4000.	90123190
	0.22	300.	2000.	91123191
High 24-Hour	2.59	220.	1337.	87053024
	2.19	340.	3179.	88012024
	2.52	330.	2438.	89060924
	2.14	220.	1337.	90041324
	2.26	340.	3179.	91030224
High 8-Hour	5.48	220.	1337.	87053016
	4.96	260.	2000.	88061816
	4.55	230.	1592.	89041916
	4.68	280.	1238.	90081616
	4.97	310.	1592.	91072416

Note: YY = year, MM = month, DD = day, HH = hour.

[a] All receptor coordinates are reported with respect to the midpoint of the Osceola Power facility stack.

Table 5-8. Maximum Predicted Generic (10 g/s) Concentrations for the Osceola Power Facility: Refined Analysis

Averaging Time	Concentration[a] ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	0.234	270	3300	91123124
	0.228	300	2900	91123124
24-Hour[b]	3.25	216	1266	97053024
	2.51	330	2438	89060924
8-Hour[b]	6.52	216	1266	87053016
	5.50	262	1600	88061816
	5.25	308	1547	91072416

Note: YY = year, MM = month, DD = day, HH = hour.

[a] All receptor coordinates are reported with respect to Osceola Power facility's colocated stack location.
[b] All short-term concentrations are highest predicted.

Table 5-9. Maximum Impacts of HAPs and Air Toxic Pollutants for Osceola Power Cogeneration Facility (total both boilers)

	Emission Rates		Concentrations (µg/m³)						Compound
	Maximum	Annual	8-Hour		24-Hour		Annual		Complies With
Pollutant	(lb/hr)	(TPY)	Impact	FARC	Impact	FARC	Impact	FARC	FARCs?
1, 1, 1 trichloroethane	0.26	0.70	0.0212	19000	0.0106	4524	4.7E-04	NA	YES
2,3,7,8 -TCDD (dioxin)	9.1E-09	2.5E-08	7.5E-10	NA	3.7E-10	NA	1.7E-11	2.2E-08	YES
acetaldehyde	1.19	3.20	0.0973	450	0.0486	107	0.0022	0.5	YES
acetone	0.578	1.56	0.0474	17800	0.0237	4238	1.0E-03	NA	YES
acetophenone	0.0056	0.015	0.0005	490	0.0002	117	1.0E-05	100	YES
acrolein	0.099	0.27	0.0081	2.3	0.0040	0.5	1.8E-04	0.02	YES
ammonia	72.96	196.99	5.9901	170	2.9877	41	0.133	100	YES
antimony	0.037	0.0060	0.0030	5	0.0015	1.2	4.0E-06	0.3	YES
arsenic	0.20	0.28	0.0162	0.1	0.0081	0.02	0.00019	0.00023	YES
barium	0.079	0.04	0.0065	5	0.0032	1.2	2.7E-05	50	YES
benzene	1.98	5.34	0.1622	30	0.0809	7	0.0036	0.12	YES
benzo (a) anthracene (POM)	0.0011	0.04	0.0001	NA	0.0000	NA	0.0000	0.0011	YES
benzo (a) pyrene	5.37E-05	1.45E-04	0.0000	NA	0.0000	NA	0.0000	0.0003	YES
beryllium	0.0063	0.00030	5.1E-04	0.02	2.6E-04	0.005	2.0E-07	0.00042	YES
bromine	0.84	0.32	0.0688	6.6	0.0343	1.6	2.2E-04	NA	YES
cadmium	0.0035	0.0052	2.9E-04	0.02	1.4E-04	0.005	3.5E-06	0.00056	YES
carbon disulfide	0.198	0.53	0.0162	310	0.0081	74	3.6E-04	200	YES
carbon tetrachloride	0.0091	0.025	0.0007	310	0.0004	74	1.7E-05	0.067	YES
chlorine	1.40	3.78	0.1148	15	0.0573	3.6	0.0025	0.4	YES
chloroform	0.071	0.19	0.0059	490	0.0029	117	1.3E-04	0.043	YES
chromium	0.24	0.34	0.0197	5	0.0098	1.2	2.3E-04	1000	YES
chromium +6	0.048	0.068	0.0040	0.5	0.0020	0.1	4.6E-05	0.000083	YES
chrysene	0.054	0.14	0.0044	2	0.0022	0.5	9.8E-05	NA	YES
cobalt	0.239	0.18	0.0196	0.5	0.0098	0.1	1.2E-04	NA	YES
copper	0.57	0.63	0.0468	10	0.0233	2.4	4.2E-04	NA	YES
cumene	0.027	0.07	0.0022	2460	0.0011	586	5.0E-05	1	YES
dibutyl phthalate	0.088	0.24	0.0072	50	0.0036	12	1.6E-04	100	YES
ethylbenzene	0.0059	0.016	0.0005	4340	0.0002	1033	1.1E-05	1000	YES
fluorine (as fluorides)	25.44	4.29	2.0887	25	1.0418	6	2.9E-03	NA	YES
formaldehyde	1.98	5.34	0.1622	3.7	0.0809	0.9	0.0036	0.077	YES
hexane	0.84	2.26	0.0686	1760	0.0342	419	0.0015	200	YES
hydrogen chloride	83.74	56.40	6.8752	70	3.4292	17	0.0380	7	YES
indium	0.193	0.52	0.0158	1	0.0079	0.2	3.5E-04	NA	YES
iodine	0.0032	0.0087	0.0003	10	0.0001	2.4	5.9E-06	NA	YES
isopropanol	13.98	37.76	1.1481	9800	0.5726	2333	2.5E-02	NA	YES
lead	0.243	0.269	0.0200	0.5	0.0100	0.1	1.8E-04	0.09	YES
manganese	0.55	0.70	0.0452	50	0.0225	12	4.7E-04	0.05	YES
mercury	0.0089	0.0168	0.0007	0.5	0.0004	0.1	1.1E-05	0.3	YES
methanol	2.28	6.16	0.1872	2600	0.0934	619	4.1E-03	NA	YES
methyl ethyl ketone	0.0182	0.049	0.0015	5900	0.0007	1405	3.3E-05	1000	YES
methyl isobutyl ketone	1.31	3.53	0.1073	2050	0.0535	488	2.4E-03	NA	YES
methylene chloride	2.28	6.16	0.1872	1740	0.0934	414	4.1E-03	2	YES
molybdenum	0.034	0.026	0.0028	50	0.0014	12	1.8E-05	NA	YES
m&p xylene	0.0119	0.032	0.0010	4340	0.0005	1033	2.2E-05	80	YES
napthalene	0.90	2.42	0.0736	500	0.0367	119	1.6E-03	NA	YES
nickel	0.0336	0.044	0.0028	10	0.0014	2.4	3.0E-05	0.0042	YES
o xylene	0.0040	0.011	0.0003	4340	0.0002	1033	7.2E-06	80	YES
PAH	8.97E-07	2.42E-06	0.0000	2	0.0000	0.5	1.6E-09	0	YES
phenols	0.062	0.17	0.0051	190	0.0026	45	1.1E-04	30	YES
phosphorus	0.91	0.160	0.0748	1	0.0373	0.2	1.1E-04	NA	YES
pom (polycyclic organic matter)	0.010	0.0090	0.0008	NA	0.0004	NA	6.1E-06	NA	YES
selenium	0.057	0.050	0.0046	2	0.0023	0.5	3.4E-05	NA	YES
silver	0.0021	0.0057	1.7E-04	0.1	8.7E-05	0.02	3.9E-06	NA	YES
styrene	0.023	0.062	0.0019	2130	0.0009	507	4.1E-05	1000	YES
sulfuric acid mist	11.22	5.59	9.2E-01	10	4.6E-01	2.4	3.8E-03	NA	YES
tin	0.0094	0.0033	7.7E-04	1	3.8E-04	0.2	2.2E-06	NA	YES
toluene	0.137	0.37	0.0112	1880	0.0056	448	2.5E-04	400	YES
trichloroethylene	0.0116	0.031	0.0009	2690	0.0005	640	2.1E-05	0.77	YES
tungsten	1.96E-05	5.3E-05	1.61E-06	50	8.03E-07	12	3.6E-08	NA	YES
uranium	1.9E-05	1.5E-05	1.6E-06	0.5	7.8E-07	0.1	1.0E-08	NA	YES
vanadium	5.9E-04	8.6E-04	4.8E-05	0.5	2.4E-05	0.1	5.8E-07	20	YES
yttrium	1.0E-04	2.7E-04	8.2E-06	10	4.1E-06	2.4	1.8E-07	NA	YES
zinc	7.59	7.06	0.6232	10	0.3108	2.4	4.8E-03	NA	YES
zirconium	6.3E-04	0.0017	5.2E-05	50	2.6E-05	12	1.1E-06	NA	YES

Notes: F'ARC= Florida Ambient Reference Concentrations
Maximum concentrations determined with ISCST3 model and West Palm Beach meteorological data for 1982 to 1986.
Highest predicted concentrations (µg/m³) for a generic emission rate of 10 g/s (79.365 lb/hr) are :

8-hour=	6.516
24-hour=	3.25
Annual=	0.234

6.0 ADDITIONAL IMPACT ANALYSIS

6.1 INTRODUCTION

Osceola is proposing to modify its permits. The facility is subject to the PSD new source review requirements for nitrogen oxides (NO_x). The additional impact analysis and the Class I area analysis address this pollutant. The analysis addresses the potential impacts on vegetation, soils, and wildlife of the surrounding area and the nearby Class I area due to Osceola's proposed modification. The nearest Class I area is the Everglades National Park (ENP), located approximately 120 kilometers (km) south of the Osceola site.

The analysis will demonstrate that the increase in impacts due to the proposed increase in emissions is extremely low. Regardless of the existing conditions in the vicinity of the site or in the Class I area, the proposed project will not cause any adverse impacts due to the predicted low impacts upon these areas.

6.2 SOIL, VEGETATION, AND AQRV ANALYSIS METHODOLOGY

In the foregoing analysis, the maximum air quality impacts predicted to occur in the vicinity of the Osceola plant and in the Class I area due to the increase in emissions are used. The analysis involved predicting worst-case maximum short- and long-term concentrations of pollutants in the vicinity of the plant and in the Class I area and comparing the maximum predicted concentrations to lowest observed effect levels for AQRVs or analogous organisms. In conducting the assessment, several assumptions were made as to how pollutants interact with the different matrices, i.e., vegetation, soils, wildlife, and aquatic environment.

A screening approach was used to evaluate potential effects which compared the maximum predicted ambient concentrations of air pollutants of concern with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted which specifically addressed the effects of air contaminants on plant species reported to occur in the vicinity of the plant and the Class I area. It was recognized that effects threshold information is not available for all species found in the ENP although studies have been performed on a few of the common species and on other similar species which can be used as models. In conducting the assessment, both direct (fumigation) and indirect (soil accumulation/uptake) exposures were considered for flora, and direct exposure (inhalation) was considered for wildlife.

6.3 IMPACTS TO SOILS, VEGETATION, AND VISIBILITY IN VICINITY OF THE OSCEOLA PLANT

6.3.1 PREDICTED AIR QUALITY IMPACTS

The results of the ambient air quality modeling for NO_x emissions due to the Osceola modification, in the vicinity of the plant, are presented in Table 6-1. Maximum predicted concentrations are presented for the annual, 24-hour, 8-hour, 3-hour, and 1-hour averaging times. These concentrations reflect the proposed increase in NO_x emissions.

6.3.2 IMPACTS TO SOILS

Air contaminants can affect soils through fumigation by gaseous forms, accumulation of compounds transformed from the gaseous state, or by the direct deposition of particulate matter or particulate matter to which certain contaminants are absorbed. The soils in the vicinity of the Osceola plant are primarily organic peat type soils. Due to the very low NO_x impacts associated with the project, no effects upon soils are expected.

6.3.3 IMPACTS TO VEGETATION

6.3.3.1 Vegetation Analysis

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation. This is a conservative approach.

6.3.3.2 Nitrogen Dioxide

A review of the literature indicates great variability in NO_2 dose-response relationship in vegetation (see Table 6-2). Acute NO_2 injury symptoms are manifested as water-soaked lesions, which first appear on the upper surface, followed by rapid tissue collapse. Low-concentration, long-term exposures as frequently encountered in polluted atmospheres often do not induce the lesions associated with acute exposures but may still result in some growth suppression. Citrus trees exposed to 470 $\mu g/m^3$ of NO_2 for 290 days showed injury (Thompson *et al.*, 1970). Sphagnum exposed for 18 months at an average concentration of 11.7 $\mu g/m^3$ showed reduced growth (Press *et al.*, 1986).

The primary crop grown in the vicinity of the site is sugar cane, along with some rice and other vegetables. The maximum ground-level NO_2 concentrations (1-hour and annual average) predicted to occur in the vicinity of the plant due to the proposed increase in emissions are 7.0 $\mu g/m^3$ and 0.10 $\mu g/m^3$, respectively (Table 6-1). These maximum predicted concentrations are well below reported effects levels. Therefore, no adverse effects on vegetation are expected due to the proposed modification.

6.3.4 IMPACTS UPON VISIBILITY

All air emission sources affected by the proposed modification are existing sources. No increase in permitted emissions is requested, except for NO_x emissions, which will increase slightly. The existing boilers are in compliance with opacity regulations and should remain in compliance after the modification. As a result, no adverse impacts upon visibility are expected.

6.3.5 IMPACTS DUE TO ASSOCIATED POPULATION GROWTH

There will be no increase in permanent employment at Osceola as a result of the proposed project. Therefore, there will be no anticipated permanent impacts on air quality caused by associated population growth.

6.4 CLASS I AREA IMPACT ANALYSIS

6.4.1 DEFINITION OF AQRVS AND CRITERIA APPLIED TO THE ENP

The ENP is classified as a Class I area by the U.S. Department of the Interior, National Park Service (NPS). In 1978, the NPS administratively defined air quality related values (AQRVs) for such areas as being:

> All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.
>
> Important attributes of an area are those values or assets that make an area significant as a natural monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).

6.4.2 AQRVS OF ENP

To date, specific AQRVs other than visibility have not been defined by NPS for the ENP (Ellen Porter, USFWS, Denver, CO, pers. comm., 1994). For this analysis, therefore, the AQRVs of this Class I area are defined as those important attributes of the ENP which are dependent upon the air environment, including water, soil, vegetation resources, and wildlife resources. All terrestrial vegetation, including threatened and endangered plant species of the ENP are dependent upon the air environment and are considered AQRVs. Some terrestrial wildlife and endangered and threatened wildlife are also considered AQRVs for ENP.

6.4.3 PREDICTED AIR QUALITY IMPACTS IN THE CLASS I AREA

The results of the air quality modeling for the increase in emissions due to the Osceola modification are presented in Table 6-3. Predicted air quality concentrations are presented for the ENP for the annual, 24-hour, 8-hour, 3-hour, and 1-hour averaging times. These concentrations reflect only the increase in emissions due to the proposed project.

6.4.4 VEGETATION AQRV ANALYSIS

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides have been also reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation. This is a conservative approach.

A review of the literature indicates great variability in NO_x dose-response relationship in vegetation (see Table 6-2). Acute NO_2 injury symptoms are manifested as water-soaked lesions, which first appear on the upper surface, followed by rapid tissue collapse. Low-concentration, long-term exposures as frequently encountered in polluted atmospheres often do not induce the lesions associated with acute exposures but may still result in some growth suppression. Citrus trees exposed to 470 $\mu g/m^3$ for 290 days showed injury (Thompson *et al.*, 1970). Sphagnum moss exposed for 18 months at an average concentration of 11.7 $\mu g/m^3$ showed reduced growth (Press *et al.*, 1986).

The maximum ground-level NO_2 concentrations (1-hour and annual average) predicted to occur at the Class I area due to the increase in emissions are 0.45 and 0.0013 $\mu g/m^3$ respectively. These values are well below reported effect concentrations and no effects are predicted to occur.

6.4.5 SOILS AQRV ANALYSIS

For soils, potential and hypothesized effects of atmospheric deposition include:

1. Increased soil acidification,
2. Alteration in cation exchange,
3. Loss of base cations, and
4. Mobilization of trace metals.

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

The soils of the Everglades National Park are generally classified as histosols or entisols. Histosols (peat soils) are organic and have extremely high buffering capacities based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs. The entisols are shallow sandy soils overlying limestone, such as the soils found in the pinelands. The direct connection of these soils with subsurface limestone tends to neutralize any acidic inputs. Moreover, the groundwater table is highly buffered due to the interaction with subsurface limestone formations which results in high alkalinity [as calcium carbonate ($CaCO_3$)].

The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of NO_x projected for the ENP from the Osceola facility emissions precludes any significant impact on soils.

6.4.6 WILDLIFE AQRV ANALYSIS

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1980; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary ambient air quality standards. Physiological and behavioral effects have been observed in experimental animals at or below these standards.

For impacts on wildlife, the lowest threshold values of NO_2 reported to cause physiological changes are shown in Table 6-4. These values are up to orders of magnitude larger than maximum predicted concentrations for the Class I area. No effects on wildlife AQRVs from NO_2 are therefore expected.

6.4.7 VISIBILITY IMPACTS

The visibility analysis required by PSD regulations is directed primarily toward Class I areas. The CAA amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory PSD Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration caused by various pollutants. The Class I area nearest to the proposed facility is the Everglades National Park, located about 120 km south of the proposed site.

A Level-1 visibility screening analysis was performed to determine the potential adverse visibility effects using the approach suggested in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA, 1988c). The level-1 screening analysis is designed to provide a conservative estimate of plume visual impacts (i.e., impacts higher than expected). The EPA model, VISCREEN, was used for this analysis. Model input and output results are presented in Table 6-5. The increase in NO_x emissions due to the proposed revision, as presented in Section 3.4, were used as input to the model. As indicated, the maximum visibility impacts caused by the facility do not exceed the screening criteria inside or outside the ENP Class I area. As a result, there is no significant impact upon visibility predicted for the Class I areas.

6.4.8 SUMMARY

In summary, it is apparent that very large margins of safety exist for all matrices examined with respect to the effects of the predicted increase in emissions on the Class I areas. No significant adverse effects will occur to the AQRVs in the ENP due to the modification of the Osceola facility.

Table 6-1. Maximum Predicted NO_x Concentrations for the Proposed Modification—Site Vicinity (Page 1 of 2)

		Receptor Location[a]		
Averaging Time	Concentration ($\mu g/m^3$)	Direction (degrees)	Distance (m)	Period Ending (YYMMDDHH)
Annual	0.08	300.	4000.	87123124
	0.08	270.	4000.	88123124
	0.09	300.	4000.	89123124
	0.10	270.	4000.	90123124
	0.09	300.	2000.	91123124
24-Hour Highest	1.12	220.	1337.	87053024
	0.94	340.	3179.	88012024
	1.09	330.	2438.	89060924
	0.92	220.	1337.	90041324
	0.98	340.	3179.	91030224
8-Hour Highest	2.4	220.	1337.	87053016
	2.1	260.	2000.	88061816
	2.0	230.	1592.	89041916
	2.0	280.	1238.	90081616
	2.1	310.	1592.	91072416
3-Hour Highest	3.8	200.	1090.	87082312
	3.7	220.	1337.	88042815
	3.4	290.	1297.	89042415
	3.3	270.	1219.	90070712
	3.8	290.	1297.	91082912

Table 6-1. Maximum Predicted NO_x Concentrations for the Proposed Modification—Site Vicinity (Page 2 of 2)

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
1-Hour Highest	7.0	250.	1297.	87071809
	5.5	140.	2000.	88042907
	6.2	180.	2000.	89121709
	5.9	330.	2438.	90060107
	4.9	160.	2000.	91042208

Note: YY = year, MM = month, DD = day, HH = hour.

[a] All receptor coordinates are reported with respect to the midpoint of the Osceola Power facility stack.

Table 6-2. Nitrogen Dioxide Doses Reported to Affect Crops

Species	Concentration ($\mu g/m^3$)	Time Period	Effect	Reference
Oats and Alfalfa	744 NO and 1,000 NO_2	1.5 hours	Temporary inhibited photosynthesis	Hill and Bennett, 1970
Tomato	310 NO and 470 NO_2	20 hours	Reduction in photosynthesis rate	Capron and Mansfield, 1976
Pinto Bean	620	10-19 days	Reduced fresh and dry weights	Taylor and Eaton, 1966
Oranges	120 to 470	290 days	Reduced number and weight of fruit	Thompson et al., 1970
Corn	1,880	14 days	No effect on growth	Okano et al., 1985
Sphagnum Moss	11.7	18 months	Reduced growth	Press et al., 1986

Note: NO = nitric oxide.
NO_2 = nitrogen dioxide.
$\mu g/m^3$ = micrograms per cubic meter.

Source: Golder Associates Inc., 1997.

Table 6-3. Maximum Predicted NO_x Concentrations for the Proposed Modification—Everglades National Park (Page 1 of 2)

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] UTM-E (m)	Receptor Location[a] UTM-N (m)	Period Ending (YYMMDDHH)
Annual	0.0010	545000.	2848600.	87123124
	0.0011	540000.	2848600.	88123124
	0.0013	550300.	2848600.	89123124
	0.0012	550300.	2848600.	90123124
	0.0013	550300.	2848600.	91123124
24-Hour Highest	0.0290	550300.	2848600.	87032924
	0.0313	540000.	2848600.	88120824
	0.0234	530000.	2848600.	89012124
	0.0217	514500.	2848600.	90012624
	0.0373	500000.	2832500.	91101924
8-Hour Highest	0.0837	550300.	2848600.	87032916
	0.0940	540000.	2848600.	88120808
	0.0702	530000.	2848600.	89012116
	0.0692	545000.	2848600.	90030424
	0.0689	550300.	2848600.	91110108
3-Hour Highest	0.1384	488500.	2845500.	87030418
	0.2506	540000.	2848600.	88120803
	0.1407	545000.	2848600.	89040621
	0.1481	540000.	2848600.	90092924
	0.1787	520000.	2848600.	91121109

Table 6-3. Maximum Predicted NO_x Concentrations for the Proposed Modification—Everglades National Park (Page 2 of 2)

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] UTM-E (m)	UTM-N (m)	Period Ending (YYMMDDHH)
1-Hour Highest	0.3924	535000.	2848600.	87090501
	0.4191	540000.	2848600.	88072123
	0.3928	548600.	2837500.	89081404
	0.4177	540000.	2848600.	90093001
	0.4450	525000.	2848600.	91121109

Note: YY = year, MM = month, DD = day, HH = hour.

[a] All receptor coordinates are reported in UTM coordinates (m).

Table 6-4. Lowest Observed Effect Levels of NO_2 in Animals

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Nitrogen Dioxide	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	95 to 950	8 hr/day for 122 days[a]

[a]Used to compare as a range between 3-hour and 24-hour averageing times.

Sources: Adapted from Newman (1980) and Newman and Schreiber (1988).

Table 6-5. Results of Visibility Impact Analysis

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                Visual Effects Screening Analysis for
                Source: OSCEOLA POWER CORP
                Class I Area: EVERGLADES NATIONAL PARK

                ***   Level-1 Screening   ***
Input Emissions for

   Particulates       .00  TON/YR
   NOx (as NO2)    149.80  TON/YR
   Primary NO2        .00  TON/YR
   Soot               .00  TON/YR
   Primary SO4        .00  TON/YR

    **** Default Particle Characteristics Assumed

              Transport Scenario Specifications:

    Background Ozone:                     .04 ppm
    Background Visual Range:            63.00 km
    Source-Observer Distance:          120.00 km
    Min. Source-Class I Distance:      120.00 km
    Max. Source-Class I Distance:      160.00 km
    Plume-Source-Observer Angle:        11.25 degrees
    Stability:   6
    Wind Speed:   1.00 m/s

                        R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

         Maximum Visual Impacts INSIDE  Class I Area
          Screening Criteria ARE NOT Exceeded
                                      Delta E      Contrast
                                    ===========  ============
Backgrnd Theta Azi Distance Alpha Crit  Plume    Crit  Plume
======== ===== === ======== ===== ====  =====    ====  =====
 SKY       10.  84.  120.0    84.  2.00  .033     .05  -.000
 SKY      140.  84.  120.0    84.  2.00  .014     .05  -.000

         Maximum Visual Impacts OUTSIDE Class I Area
          Screening Criteria ARE NOT Exceeded
                                      Delta E      Contrast
                                    ===========  ============
Backgrnd Theta Azi Distance Alpha Crit  Plume    Crit  Plume
======== ===== === ======== ===== ====  =====    ====  =====
 SKY       10.  70.  114.1    99.  2.00  .035     .05  -.000
 SKY      140.  70.  114.1    99.  2.00  .014     .05  -.000
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July 1, 1997

Al Linero, PE
Administrator - New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

**Re: Osceola Power Limited Partnership
Permit Modification of NOx Emissions Limits**

Dear Mr. Linero:

This facility recently contacted me and indicated that they were preparing an application to modify the NOx emission limiting standard from 0.12 lb NOx per mmBTU to 0.15 lb NOx per mmBTU. This revised limit would be consistent with the sister cogeneration plant, Okeelanta Power Limited Partnership. I offer the following comments:

- The request would result in an increase in potential emissions.
- The initial NOx emission limiting standard was the result of the Department's "NOx RACT Determination" for this facility back in 1993. My recollection is that the ERC determined that NOx RACT could not be applied on a case-by-case basis. The Department was required to re-write the major source NOx RACT rule in general terms for specific types of equipment. Should the Department revise this rule to include the cogeneration boilers?
- Due to the similarity of the boilers and fuels, I can think of no reason why the NOx emission limiting standard shouldn't be the same.

Thank you for the opportunity to comment on this issue. If you have any questions, please contact me at the numbers below.

Sincerely,

For the Division Director
Environmental Health and Engineering

Jeffery J. Koerner

Jeffery F. Koerner, PE
Air Pollution Control Section
Phone: (561) 355-4549 SunCom: 273-4549
FAX: (561) 355-2442

Filename: LINERO_2.LTR

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FLORIDA DEPARTMENT OF HEALTH

Lawton Chiles, Governor James T. Howell, M.D., M.P.H., Secretary

July 1, 1997

Al Linero, PE
Administrator - New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
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7/2
Waiting on a new request - then start a new file -

Filename: LINERO_2.LTR

THE PALM BEACH POST

Published Daily and Sunday
West Palm Beach, Palm Beach County, Florida

PROOF OF PUBLICATION

STATE OF FLORIDA
COUNTY OF PALM BEACH

Before the undersigned authority personally appeared **Chris Bull** who on oath says that she is **Classified Advertising Manager** of The Palm Beach Post, a daily and Sunday newspaper published at West Palm Beach in Palm Beach County, Florida; that the attached copy of advertising, being a **Notice** in the matter of **Intent to Issue air const. permit modif.** in the - - - Court, was published in said newspaper in the issues of **September 12, 1997.**

Affiant further says that the said The Post is a newspaper published at West Palm Beach, in said Palm Beach County, Florida, and that the said newspaper has heretofore been continuously published in said Palm Beach County, Florida, daily and Sunday and has been entered as second class mail matter at the post office in West Palm Beach, in said Palm Beach County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she/he has neither paid nor promised any person, firm or corporation any discount rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sworn to and subscribed before me 15 day of September A.D. 1997

Personally known **XX** or Produced Identification ________
Type of Identification Produced ________

NOTARY PUBLIC STATE OF FLORIDA
Karen McLinton
Notary Public, State of Florida
Commission No. CC 591337
My Commission Exp. 11/15/2000
1-800-3-NOTARY Fla. Notary Service & Bonding Co.

NO. 393371
PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION
STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
DRAFT Permit Modification No. 0990331-006-AC, PSD-FL-197E
Osceola Cogeneration Facility
Palm Beach County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to Osceola Power Limited Partnership, for increases in emissions from the cogeneration facility located at U.S. Highway 98 and Hatton Highway in Pahokee, Palm Beach County. A Best Available Control Technology (BACT) determination was required for nitrogen oxides pursuant to Rules 62-212.400 and 410, F.A.C., Prevention of Significant Deterioration (PSD). The facility consists of two multiple fuel boilers which produce steam for use by the adjacent Osceola Farms sugar mill and up to 74 megawatts of electricity. The applicant's name and address are: Osceola Power Limited Partnership, Post Office Box 606, Pahokee, Florida 33476. The permit is to revise allowable limits for lead (Pb), sulful dioxide (SO2), nitrogen oxides (NOx) and Mercury (Hg) when burning woodwaste; revise carbon monoxide (CO) and NOx while burning fuel oil; and revise the averaging time for CO for all uels. Annual emissions will increase only for Pb and NOx, but only the NOx increase is significant with respect to PSD. Emissions of NOx will increase by approximately 100 tons per year (TPY). Control is accomplished by injection of urea into the furnace through Selective Non-Catalytic Reduction (SNCR). The proposed emission limit is 0.14 pounds of NOx per million Btu of heat input (lb/MMBtu) when burning woodwaste or fuel oil and is among the lowest in the country for multiple fuel boilers. The new limit will also reduce ammonia emissions (slip), improve electrostatic precipitator efficiency, and reduce plume opacity. An air quality impact analysis was conducted. Tha maximum impact is below the significant impact level of 1 microgram per cubic meter (pg/m3). Emissions from the facility will consume PSD increment but will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The maximum predicted PSD Class II NOx increment consumed by this project will be 0.4 percent of the allowable increment of 25 pg/m3 for all projects in the area. The project has an insignificant impact on the Everglades Class I area for the NOx annual avaraging time.

The Department will issue the FINAL Permit Modification, in accordance with the conditions of the DRAFT Permit Modification unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed DRAFT Permit Modification issuance action for a period of 30 (thirty) days from the date of publication of this Notice. Writtan comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit Modification, the Department shall issue a Ravised DRAFT Permit Modification and require, if applicable, another Public Notice. The Department will issue FINAL Permit Modification with the conditions of the DRAFT Parmit Modification unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S. The procedures for petitioning for a hearing are set forth balow. Mediation is not available for this action. A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulavard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 850/488-9370, fax: 850/487-4938. Petitions must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination under Sections 120.589 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28.5.207 of the Florida Administrative Code. A petition must contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action of proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statemant of the material facts disputed by petitioner, if any; (e) A statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement identifying the roles or statutes that the petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the Department's action or proposed action addressed in this notice of intent. Because the administrative hearing process is designed to forumulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notica of intent. Persons whosa substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. A complete project file is available for public inspection during normal businss hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/488-1344
Fax: 850/922-6979

Dept. of Environmental Protection
South District Office
2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901
Telephone: 813/332-6975
Fax: 813/332-6969

Palm Beach County Public Health Unit
901 Evernia Street
Post Office Box 29
West Palm Beach, Florida 33401
Telephone: 581/355-3070
Fax: 561/355-2442

The complate project file includes the Draft Permit Modification, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-1344, for additional information.

PUB: The Palm Beach Post
September 12, 1997

P 265 659 451

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Carlos Rionda	
Street & Number Osceola Power	
Post Office, State, & ZIP Code Pahokee Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 9-9-97 0990331-006-AC PSD-FI-~~[illegible]~~ 197E	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Carlos Rionda, AR
Osceola Power, LP
P O Box 606
Pahokee, Fl
33476

4a. Article Number
P 265 659 451

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
9-11-97

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Anthony McPhee

PS Form **3811**, December 1994

Domestic Return Receipt

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